701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5027
Fax 202-508-5150
qshea@eei.org

www.eei.org

**EDISON ELECTRIC INSTITUTE**

QUINLAN J. SHEA, III
Executive Director, Environment

June 29, 2004

**Via E-mail**

EPA Docket Center
Attention Docket ID No. OAR-2002-0056
Room B-108
U.S. EPA West
1301 Constitution Avenue, NW
Washington, DC 20460

**Re: Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units – 69 Fed. Reg. 4652 (January 30, 2004) *and* Supplemental Notice – 69 Fed. Reg. 12398 (March 16, 2004)**

Dear Sir or Madam:

The Edison Electric Institute (EEI) appreciates the opportunity to submit the enclosed comments on the Environmental Protection Agency's (EPA) utility mercury and nickel reduction proposal. The balance of this letter provides a brief summary of EEI's comments.

EEI is the association of shareholder-owned electric companies, international affiliates and industry associates worldwide. Our U.S. members serve more than 90 percent of the ultimate customers in the shareholder-owned segment of the industry, and nearly 70 percent of all electric utility ultimate customers in the nation. They generate almost 70 percent of the electricity generated by U.S. electric utilities. EEI members have a crucial interest in the mercury proposal, which will require the installation of new emission control equipment over the next decade and a half at a cumulative cost of billions of dollars.

EEI's comments raise several policy issues related to our industry's progress to date in reducing emissions and our views on appropriate next steps to take. EEI is generally supportive of the policy objectives underlying EPA's proposed rule and shares EPA's commitment to make sensible emission reductions from power generating facilities.

As a threshold matter, EEI acknowledges the fact that mercury in the human body, at high enough levels, can cause adverse neurological and developmental effects in fetuses and children. EEI and its members share the goal of protecting public health and are prepared to make reasonable additional reductions in power plant mercury emissions. We want to ensure, however, that any actions we take that could raise the cost of electricity to consumers brings them commensurate health and environmental benefits.

It is crucial that any regulatory requirements result in a level playing field for all affected sources. In addition, compliance timeframes must be flexible and harmonized with the Clean Air Interstate Rule (CAIR; formerly the Interstate Air Quality Rule) to ensure continued reliability and feasibly allow the capital investment of billions of dollars, and because there are no currently available commercial technologies designed exclusively for mercury control from electric utilities.

Major issues raised in EEI's comments are highlighted below.

**We Need to Build on the Substantial Progress to Date**

The air quality in America has improved dramatically, and America's electric companies have made tremendous progress in powering our growing economy and delivering cleaner energy by reducing our emissions. They are taking a sensible approach to reducing pollution while continuing to produce the energy our nation's economy needs to grow – at prices that families and businesses can afford. And we are developing new technologies to allow America's electric companies to do even more in the future, passing on the benefits of even cleaner energy to America's next generation.

Despite the fact that there are no currently available commercial technologies designed exclusively for mercury control from coal-based power plants, currently installed pollution controls for particulates, $NO_x$ and $SO_2$ already capture about 40 percent of the 75 tons of mercury that enters power plants in the coal.

The electric generation industry supports further reductions of $SO_2$, $NO_x$, and mercury emissions, though details of any new program must embrace the following, equally important goals:

- Making substantial environmental improvements,
- Providing business certainty and flexibility,
- Minimizing costs to customers and impacts on shareholders,
- Not exacerbating current strains on natural gas supply and prices,
- Maintaining fuel diversity for the industry, and
- Continuing reliable electric generation.

## Multi-Emission Legislation is the Best Approach

A legislative strategy for improving air quality – with clear, congressionally mandated emissions cuts from power plants – would provide for greater certainty and produce air quality improvements almost immediately. The Administration's Clear Skies Act is a workable, reasonable means of accomplishing these goals.

## Sufficient Time is Needed

A key concern is whether power generators have enough time to install all the control technologies that would be needed to meet the CAIR and mercury program mandates, especially for reduction requirements imminent in the next half decade. In its CAIR comments, EEI suggests that EPA take into consideration the difficulty for some companies to meet the 2010 targets and provide a regulatory fix to this almost inevitable problem. The same regulatory considerations should be provided for a mercury cap-and-trade program that relies on supposed CAIR co-benefits.

The technology-based (MACT) alternative would require massive mercury reductions by 2008, two years before the $SO_2$ and $NO_x$ reductions of the CAIR. EPA must harmonize the mercury compliance dates with the deadlines for the $SO_2$ and $NO_x$ reductions.

## Fuel Diversity is Vital

No individual fuel is capable of providing the energy to meet all of our nation's electricity demands. Certain fuels in the electricity generation mix are better suited than others for particular applications. That is why a variety of fuels – as well as increasingly more cost-effective and efficient ways to use, and conserve, energy – is needed.

Coal-based electric generators face emissions control requirements that are duplicative, contradictory, costly, and complex, and create enormous uncertainty for future investment. Currently there are more than a dozen separate regulations for $SO_2$ and $NO_x$ alone, and additional regulations are just around the corner. Adding mercury regulations to this already large and complicated list further complicates this issue. EPA needs to consider this as the agency moves forward in the regulatory process.

## Cap-and-Trade is the Preferred Option

EEI supports cap-and-trade as the preferred option for regulating electric power sector mercury emissions. EEI believes that EPA has the authority to establish a cap-and-trade program under either §111 or §112 of the CAA. EPA's MACT alternative would be far more expensive nationwide – yet less effective in reducing mercury emissions – than a national cap-and-trade approach.

A multi-emission cap-and-trade program is the most cost-effective way of achieving substantial emission reductions from the power generation industry. Trading should be allowed across the largest area possible to capitalize on all efficiencies. EPA should make every attempt to promote unfettered emissions trading in the final mercury rule.

EEI believes there is no evidence of coal-based, power-plant-related mercury "hot spots" in the U.S., and EPA's proposed mercury cap-and-trade program will not create them. Cap-and-trade programs promote economically efficient decisions to reduce emissions from power plants. Units with the highest mercury emissions will be among the first to be controlled since the cost per pound of mercury controlled will be the lowest at these units. The CAIR proposal and other pending state and federal regulations will require the installation of pollution controls that also will capture the forms of mercury that tend to deposit nearby. Finally, the economics of trading will help to minimize local deposition since large coal-based power plants will tend to control their emissions first, and most likely more than required.

**Key Health Effects Issues Remain Unresolved**

In its December 2000 regulatory determination, EPA noted "there are uncertainties regarding the extent of the risks due to electric utility mercury emissions." Previously, in its *Mercury Research Strategy*, EPA stated that "[t]he amount of mercury deposited in the United States that can be directly attributed to domestic combustion sources remains uncertain." Three years later, after extensive research on the fate and transport and atmospheric chemistry of mercury, EPA stated in the proposed mercury rule that the agency "cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems." Further, in addressing the state of the science, the proposed rule notes that "the relationship between Hg emission reductions from Utility Units and methylmercury concentrations in fish cannot be calculated in a quantitative manner with confidence." Finally, EPA admits that "[t]he Agency is unable to provide a monetized estimate of the benefits of Hg (mercury) and Ni (Nickel) emissions reduced by the proposed rule at this time."

Recent and comprehensive research undertaken by the Centers for Disease Control and Prevention (CDC), which measured mercury in the blood of women, indicates that people in the U.S. are not being exposed to levels of mercury considered to be harmful to fetuses, children, or adults. According to the CDC, "The levels reported in this NHANES [National Health and Nutrition Examination Survey] 1999-2000 subsample for maternal-aged females were below levels associated with *in utero* effects on the fetus, or with effects in children and adults (National Academy of Sciences, 2000)."

## Mercury Control Technologies Remain Under Development

Reliable, cost-effective control technologies designed specifically for capturing mercury have not yet been fully developed or tested. EPRI, DOE, and EPA have conducted extensive R&D programs over the past decade with the objective of developing cost-effective methods for reducing power plant mercury emissions. Mercury control technology capable of achieving high removal rates (*i.e.,* greater than 80 percent) across the entire industry is not available. Full-scale demonstrations of mercury control technologies at individual power plants are just getting underway. It will take at least two-three years to complete these initial demonstrations and evaluate the potential effectiveness of possible new control technologies. And then, several more years will be needed before these technologies can be considered "commercially available."

## EEI Modifications to the EPA Cap-and-Trade Program

EEI recognizes that the agency is attempting to provide the electric utility industry flexibility to achieve mercury reductions in a non-prescriptive and cost-effective manner via the cap-and-trade option. Nevertheless, the cap-and-trade program as proposed needs modification. EEI's alternative – which adds a third phase – can be summarized as follows:

- EEI does not support a specific numeric Phase 1 cap in 2010; *i.e.*, the "cap" is only what is achieved by "co-benefit" reductions from controls added in the 29 states covered by the CAIR proposal.
- EEI supports and proposes an interim cap of 24 tons in 2015. The mercury trading program would begin that year and mercury allowances would be allocated. Allowances would be based on heat input.
- EEI supports the 15-ton cap in 2018.
- EEI proposes no banking of allowances until the 2015 interim phase.
- EEI members would be willing to begin some form of mercury monitoring in 2008. Coal-based power plants could install and certify mercury CEMS or Method 324 sorbent trap monitoring systems before January 1, 2009. Continuous monitoring and reporting of mercury emissions will begin on January 1, 2009.

EEI believes that this alternative cap-and-trade program has a number of advantages over the one proposed by EPA. First, it accurately addresses the level of co-benefits in 2010 by not setting a numeric cap. Second, it significantly reduces the amount of banking that can occur prior to 2018. Thus, actual coal-based power plant emissions in 2018 are likely to be very close to or at 15 tons. Finally, the EEI alternative achieves greater mercury reductions sooner than EPA's proposal.

**EPA has No Jurisdiction to Regulate Nickel from Oil-fired Plants**

EEI strongly believes that EPA has no jurisdiction to regulate nickel from oil-fired plants since specific health concerns associated with HAP emissions were not identified when EPA listed those units under §112(c). Until EPA identifies and factually supports specific public health concerns associated with the emission of a given HAP, the agency does not have jurisdiction to regulate nickel emissions from oil-fired units.

* * *

In conclusion, despite dramatic emission decreases from the electric generating sector in recent decades, further cost-effective reductions in emissions may be achieved under the proper framework, especially under a properly designed national cap-and-trade program. Legislation provides greater certainty for business and the environment, while regulation generally fails to address the overlapping nature of more than a dozen existing interconnected air programs. Any new regulations must begin to integrate and streamline these programs if the mercury rule is to achieve the desired emission reductions at reasonable cost to the American consumer. A cap-and-trade approach is the best way to reduce emissions from the electric utility industry. Such a rule would be protective of public health, scientifically sound, flexible, and cost-effective – all components of reasonable and sensible public policy.

EEI appreciates the opportunity to provide comments on the utility mercury and nickel reduction proposal. Questions should be directed to me or Michael Rossler, Manager, Environmental Programs (202/508-5516, mrossler@eei.org).

Sincerely,

Quinlan J. Shea, III

Enclosure

cc (w/enc): Honorable Jeffrey Holmstead, EPA
William Wehrum, EPA

# COMMENTS OF EDISON ELECTRIC INSTITUTE TO ENVIRONMENTAL PROTECTION AGENCY IN RESPONSE TO

## 40 CFR Parts 60 and 63
## Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule

## 40 CFR Parts 60, 72, and 75
## Supplemental Notice for the Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule

**June 29, 2004**

## TABLE OF CONTENTS


Page Number

I. WE NEED TO BUILD ON THE SUBSTANTIAL PROGRESS TO DATE . . . . . . . . . . . 1

A. Substantial Reductions in Emissions Already Have Been Achieved . . . . . . . . . . . 1
B. Substantial Reductions Will Continue . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 2

II. EEI SUPPORTS EFFICIENT ACTIONS TO FURTHER REDUCE EMISSIONS . . . . . . 2

III. MULTI-EMISSION LEGISLATION IS THE BEST APPROACH . . . . . . . . . . . . . . . 4

IV. SUFFICIENT TIME IS NEEDED TO MAINTAIN RELIABLE AND COST-EFFECTIVE ELECTRIC GENERATION . . . . . . . . . . . . . . . . . . . . . . . . . . . . 5

V. IMPORTANCE OF FUEL DIVERSITY . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 7
A. Electric Companies Use a Diverse Mix of Fuels to Generate Electricity . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 7
B. Fuel Diversity Must be Supported, Not Restricted, by Public Policies . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 8
C. Fuel Diversity and Infrastructure Should be Enhanced . . . . . . . . . . . . . . . . . 9

VI. CAP-AND-TRADE IS THE PREFERRED POLICY OPTION . . . . . . . . . . . . . . . . 10

A. Regulatory Flexibility Through Emissions Trading is Imperative . . . . . . . . . . . . 11
B. Emission Trading “Hot Spots” . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 12
1. “Hot spots” do not exist . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 12
2. The Florida everglades study is flawed . . . . . . . . . . . . . . . . . . . . 13
3. Cap-and-trade will not create “hot spots” . . . . . . . . . . . . . . . . . . . 15
4. Most power plant mercury emissions will not deposit locally . . . . . . . . . . . 17

VII. HEALTH EFFECTS OF MERCURY FROM POWER PLANTS HAVE NOT BEEN DEMONSTRATED . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 18

A. EPA Acknowledges Uncertainties in Assessing Health Risks . . . . . . . . . . . . . 18
B. Health Benefits of Eating Fish . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 19
C. Eliminating Mercury Emissions From U.S. Utilities Will Not Change Fish Advisories . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 21
C. There is Little Actual Exposure to Methylmercury in the U.S. . . . . . . . . . . . . . . 25

VIII. STATUS OF CONTROL TECHNOLOGIES . . . . . . . . . . . . . . . . . . . . . . . . 26

A. Overview . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 26
B. Co-Benefits and Current Technologies . . . . . . . . . . . . . . . . . . . . . . . . . . 27
1. “Co-benefits” as defined in the proposed rule . . . . . . . . . . . . . . . . . . 27
2. “Co-benefits” from existing controls . . . . . . . . . . . . . . . . . . . . . . . 28
a. mercury co-benefits with FGD . . . . . . . . . . . . . . . . . . . . . . . . . 29
b. mercury co-benefits with SCR . . . . . . . . . . . . . . . . . . . . . . . . . 30
3. Limitations of current technologies . . . . . . . . . . . . . . . . . . . . . . . . 32
C. Future Controls: Sorbent Injection . . . . . . . . . . . . . . . . . . . . . . . . . . . . 32

D. Coal Combustion Products . . . 34
E. Summary . . . 35

IX. COMMENTS ON MERCURY PROPOSAL . . . 36

A. Cap-and-Trade vs. MACT . . . 36
B. Cap-and-Trade Alternative Control Option . . . 38
1. Cap-and-trade under §112 . . . 38
2. Cap-and-trade under §111 . . . 40
a. authority to regulate HAPs . . . 40
b. standard of performance . . . 41
3. Design of a mercury cap-and-trade program. . . . 44
a. baseline for allowance allocation . . . 44
b. permanent allocations with a set-aside for new sources . . . 44
c. auctions . . . 45
d. banking of allowances without restriction . . . 45
e. early reduction credits . . . 46
f. units emitting less than 25 pounds of mercury per year should be excluded . . . 46
g. all units should surrender the same numbers of allowances anywhere in the U.S. . . . 47
h. facility-wide compliance . . . 47
i. monitoring and compliance . . . 47
C. EEI Alternative to EPA Cap-and-Trade Option . . . 48
1. Phase 1 should be the true co-benefits level . . . 48
2. Early mercury emissions monitoring . . . 50
3. Mercury trading would begin in 2015 . . . 51
4. Advantages of alternative cap-and-trade program . . . 51
D. MACT Alternative Control Option . . . 52
1. The recommendations of the “Industry Stakeholder Group” should be the basis of any MACT program . . . 52
2. Subcategorization . . . 52
3. MACT floors . . . 53
4. Beyond-the-floor analysis . . . 54
5. Form of standard . . . 55
6. Compliance issues . . . 55
7. Compliance time . . . 56
E. New Sources . . . 58

X. COMMENTS ON NICKEL PROPOSAL . . . 60

A. EPA’s Decision to Regulate is Inappropriate . . . 60
B. Other Issues . . . 61
1. Format of the standard . . . 61
2. Compliance . . . 62
3. Monitoring and testing deadlines . . . 62
4. Definitions . . . 62
5. Certain units should be excluded . . . 63

XI. CONCLUSIONS . . . 64

APPENDIX A: RECOMMENDATIONS OF THE “INDUSTRY STAKEHOLDER GROUP” . . . . 66

a. Subcategorization . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 66
b. MACT Floors . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 66
c. Beyond-the-Floor Regulation . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 66
d. New Units . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 66
e. Format of Standard . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 66
f. Compliance Monitoring Method . . . . . . . . . . . . . . . . . . . . . . . . . . . 67
g. Compliance Unit . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 67
h. Compliance Time . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 67
i. Oil-Fired Plants . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 67

# I. WE NEED TO BUILD ON THE SUBSTANTIAL PROGRESS TO DATE

## A. Substantial Reductions in Emissions Already Have Been Achieved

Electric generators in the United States, including EEI members, already have achieved massive reductions in their sulfur dioxide ($SO_2$) and nitrogen oxide ($NO_x$) emissions under existing Clean Air Act (CAA) programs. For example, electric generating units (EGUs) have dramatically reduced $SO_2$ emissions through the Acid Rain Program of Title IV of the Act, and those reductions are continuing. Coal-based EGUs also have substantially reduced $NO_x$ emissions through widespread installation and use of combustion controls to meet the Title IV $NO_x$ requirements. (In addition, many EGUs in the eastern half of the United States have cut their $NO_x$ emissions even further in response to the $NO_x$ SIP Call rule.[1]) EGUs in Northeastern states also achieved $NO_x$ reductions pursuant to the 1994 Ozone Transport Commission (OTC) Memorandum of Understanding (MOU) program.

In particular, $SO_2$ emissions from power plants in 2002 were nine percent lower than in 2000 and 41 percent lower than in 1980. Power plant $NO_x$ emissions also continue a downward trend, with a 13 percent reduction from 2000 and a 33 percent decline from 1990 emissions levels. The $NO_x$ reduction will reach 40 percent this year.

Despite the fact that there are no commercially available technologies designed exclusively for mercury control from coal-based power plants, currently installed pollution controls for particulates, $NO_x$ and $SO_2$ already capture about 40 percent of the 75 tons of mercury that enters power plants in the coal. Electric utilities in the U.S. release about 48 tons of mercury per year, which is roughly one-third of total anthropogenic emissions of mercury in the U.S., less than 20 percent of total anthropogenic North American emissions, and about one percent of total global mercury emissions.

[1] EPA promulgated this rule in 1998; the rule went into effect in several Northeastern states in 2003 and goes into effect in May 2004 in other states in the Midwest and Southeast.

### B. Substantial Reductions Will Continue

U.S. industries have made major strides in cutting $SO_2$, $NO_x$, and particulate emissions, and will do much more. Emissions from automobiles, trucks, power plants and other sources are scheduled to be further reduced under a number of CAA programs, including the acid rain program, new diesel standards, and other regulations under development by EPA. Future emissions from power plants will be reduced dramatically under proposed EPA regulations – the Clean Air Interstate Rule (CAIR; formerly the Interstate Air Quality Rule) and the mercury rule – or perhaps through new federal legislation, by Congress *e.g.,* Clear Skies. Either way, emissions will be reduced by another two-thirds from current levels over the next decade or so. Emission rates per ton of coal used will be reduced by 90 percent from their peaks.

As stated above, either implementation of the CAIR/mercury regulatory proposals, or the Clear Skies option will provide significant additional emission reductions from the electric utility sector over the next 10-15 years. These proposed rules cannot in any way be interpreted as a rollback of the Clean Air Act. EPA has stated that the combination of the proposed CAIR and mercury regulations will demand the largest single industry investment in emission reductions in the history of the Clean Air Act. This is on top of past emission reductions costing tens of billions of dollars in capital and billions annually for operation and maintenance.

## II. EEI SUPPORTS EFFICIENT ACTIONS TO FURTHER REDUCE EMISSIONS

EEI has discussed multi-emission approaches in earnest with EPA, environmental groups and Congress since the mid-1990s. these efforts have included the 1996 Clean Air Power Initiative dialogue, the 1998-1999 Air Quality Integration Dialogue, and, more recently, discussions between electric power CEOs and environmental group leaders, and Congressional testimony regarding federal multi-emission legislation such as the proposed Clear Skies Act.

The electric generation industry supports further reductions of $SO_2$, $NO_x$, and mercury emissions, though details of any new program must embrace the following, equally important goals:

- Making substantial environmental improvements,
- Providing business certainty and flexibility,
- Minimizing costs to customers and impacts on shareholders,
- Not exacerbating current strains on natural gas supply and prices,
- Maintaining fuel diversity for the industry, and
- Continuing reliable electric generation.

The realization of these goals is dependent upon the right levels of reductions and the right timetable for emissions cuts.

A good example of the need to jointly consider environment, energy and economics occurs in states where electric utilities are still subject to state regulation of rates. In those states, utility regulators are very diligent in ensuring that regulated entities engage in prudent, lowest-cost expenditures for environmental requirements. All expenditures – whether mandated or "voluntary" – for emissions reductions are closely scrutinized for their potential impact on customer rates. In fact, state statutes may require that all contemplated emission controls be pre-approved by the state utility commission, and states may impose a standard upon utilities to balance energy, economic and environmental considerations to ensure reasonable rates.

Coal-based power plants currently face a large number of air quality requirements that are duplicative and inefficient, thereby creating considerable uncertainty. For many years, the industry has supported a multi-emission approach that would streamline requirements, providing not only certainty in the amount and timing of emissions reductions, but also the resolution of the new source review (NSR) quandary. A flexible, certain control program would allow for efficient planning about the existing and future generation fleet. It would reduce or eliminate the never-ending litigation that often delays environmental progress. If done right, a comprehensive approach targeting $SO_2$, $NO_x$, mercury and other pollutants could lower costs compared to the current litigation-based system, while maintaining the nation's diverse fuel mix.

Critical to any successful approach is allowing sufficient time for installing new emission controls, while also maintaining incentives for development of new technologies.

## III. MULTI-EMISSION LEGISLATION IS THE BEST APPROACH

While crucial amendments are needed to address problems with the timing of the first phase, the Administration's Clear Skies Act is a workable, reasonable means of accomplishing these goals. As the CAA has been amended over time, it has become riddled with requirements that are duplicative, contradictory, costly and complex. As a result, the law has often fallen short of its goal of providing emission reductions in a timely and cost-effective manner.

A legislative strategy for improving air quality – with clear, congressionally mandated emissions cuts from power plants – would provide for greater certainty and produce air quality improvements almost immediately. The Clear Skies approach would provide electric generators with <u>greater</u> certainty and flexibility, allowing companies to better plan how to comply with the emission reduction requirements. This would allow companies to keep costs to consumers as low as possible.

Clear Skies can deliver benefits with more certainty than the proposed rules. Clear Skies targets and timetables[2] could be established immediately and thus costly and time-consuming litigation would be significantly reduced or eliminated. Clear Skies would eliminate a patchwork of different programs and implementation schedules in different states, avoiding unnecessary constraints on compliance options. As a Congressional mandate, Clear Skies would clarify and simplify the CAA for affected

[2] The timetables must be revisited now that so much time has elapsed since its introduction.

power generators, while the proposed rules would simply be layered on top of the existing regulatory labyrinth.

We agree with EPA Administrator Leavitt who stated last December that, "…we continue to believe that the Clear Skies Act is the best approach to reducing power plant emissions."

Like EPA, EEI would prefer that any new $SO_2$, $NO_x$, and mercury emission reduction targets be set out in multi-emission legislation because of the greater business certainty this approach provides. The CAIR and mercury reduction proposals, in addition to being layered on top of existing $SO_2$ and $NO_x$ requirements, would be susceptible to being overturned judicially or modified by a future Administration, factors that could delay progress.

Finally, EEI believes that EPA has taken a significant step toward trying to find the most efficient and cost-effective emissions reduction solution by aligning the proposed mercury rule with rules for ozone and particulate matter, and by proposing a cap-and-trade approach in the CAIR and mercury programs. While these rules provide less certainty than multi-emission legislation such as Clear Skies, a multi-pollutant regulatory approach is far better than the continued reliance on piecemeal programs under current regulations.

## IV. SUFFICIENT TIME IS NEEDED TO ENSURE RELIABLE AND COST-EFFECTIVE ELECTRIC GENERATION IS MAINTAINED

A key concern about CAIR is whether power generators have enough time to install all the control technologies that would be needed to meet mercury program mandates, especially for reduction requirements imminent in the next half decade.

EPA predicts, based on the CAIR proposal, that almost 80 GW of capacity would install either flue gas desulfurization or selective catalytic reduction to reduce $SO_2$ and $NO_x$, respectively, between 2005 and 2010. EPA assumes that companies will not implement construction activities until 2007 when the states and EPA finalize requirements, leaving just three years (2007, 2008 and 2009) to install control technologies on hundreds of generating units. While some companies may be able to achieve compliance under this schedule, many others will not be able to do so. It is crucial that installations be spread over time to ensure reliable and low-cost electric generation.

Further, depending on the mercury program decisions made by EPA, the amount of additional control technology applications beyond those of the CAIR could be large, especially if the technology-based (MACT) option is chosen; if a stringent cap-and-trade option is chosen that goes beyond co-benefits; or if §111 is chosen to implement a cap and trade program and states opt not to allow mercury trading.

Simultaneous installations of controls under the CAIR and mercury programs at hundreds of units imposes substantial demands on labor, materials, and state and local permitting agencies. The process for a single installation involves a complicated engineering review, negotiation of contracts with vendors, obtaining permits from local and state authorities, and engaging contractors, materials and machinery at the site for construction. All this must be done in an environment where expert labor is limited, especially boilermakers. In addition to a shortage of boilermakers, such simultaneous implementation could cause a shortage of electricians, pipefitters and ironworkers. Further, installations take the plant off-line for weeks, and such outages must be coordinated within the company and throughout the region with other types of outages in order to avoid stretching the generation capacity too thin and compromising reliability.

EPA assumes, optimistically, that the CAIR installations can be made in hundreds of locations concurrently, in less time than electric companies believe possible. Installing one scrubber requires approximately 48-54 months, including about 12 months to select the appropriate technology and establish design criteria; 12-18 months for engineering and design; and 24-30 months (depending on weather) for construction and startup. In addition, the permitting process can take years, especially for associated landfill facilities. These time constraints would be aggravated by hundreds of affected sources potentially installing control equipment within the same limited time frame.

In its CAIR comments, EEI suggests that EPA take into consideration the difficulty for some companies in meeting the 2010 targets and provide a solution to this almost inevitable problem. The same regulatory considerations should be provided for a mercury cap-and-trade program that relies on supposed CAIR co-benefits.

Even more serious concerns arise should EPA choose the MACT alternative. This apparently would require massive mercury reductions by 2008, two years before the $SO_2$ and $NO_x$ reductions of the CAIR. EPA must harmonize the mercury compliance dates with the deadlines for the $SO_2$ and $NO_x$ reductions. Only coordination of these control programs will permit affected entities to develop cost-effective planning strategies that effectively allow them to take advantage of co-benefit mercury reductions. Failure to synchronize these deadlines could unnecessarily increase electric rates and impair reliability.

If the §112 MACT alternative is chosen by EPA in the final rule, EEI strongly recommends that a 1-year extension be granted for all facilities. We note, however, that even more time may be needed to bring many other facilities into compliance. Later in these comments (section IX) we explain why a two-year presidential extension also may be necessary for many coal-based units.

## V. FUEL DIVERSITY IS IMPORTANT

### A. Electric Companies Use a Diverse Mix of Fuels to Generate Electricity

Electricity is the backbone of our modern economy. Advancements in technology have increased U.S. productivity and driven growth, and many technologies have increased electricity demand. Currently, coal generation provides 50.1 percent of the nation's electricity supply, nuclear generation provides 20.3 percent, natural gas provides 18.1 percent, hydropower and other renewables provide 9.1 percent, and oil generation provides 2.4 percent.

No individual fuel is capable of providing the energy to meet all of our nation's electricity demands. Certain fuels in the electricity generation mix are better suited than others for particular applications. That's why a variety of fuels – as well as increasingly more cost-effective and efficient ways to use and conserve energy – is needed.

### B. Fuel Diversity Must be Supported, Not Restricted, by Public Policies

Low-cost, reliable electricity results in part from our ability to utilize a variety of readily available energy resources – coal, nuclear energy, natural gas and hydropower, and other renewable energy resources. Fuel diversity is key to affordable and reliable electricity. A diverse fuel mix also helps to protect consumers from contingencies such as fuel unavailability, price fluctuations and changes in regulatory practices.

According to the Energy Information Administration (EIA), electricity consumption is growing strongly and will increase 54 percent by 2025. Maintaining diverse supply options will be key to powering the 21st century. Public policies can restrict fuel generation options, making it critical that policymakers and regulators work together to reconcile conflicting energy, environmental, or other public policy goals. The conflicts arising between regulatory policies and the activities needed to ensure the continued availability of low-cost electricity can be addressed in a manner that minimizes the unintended consequences on fuel diversity. Other national priorities – such as environmental protection, public health, and the proper stewardship and conservation of our nation's lands and finite resources – can be met through the use of market-based mechanisms, technological innovation, and the coordination of multiple, crosscutting regulatory requirements.

Every fuel source used to generate electricity is now confronted with challenges, but none more so than coal. Coal-based electric generators face emissions control requirements that are duplicative, contradictory, costly, and complex, and create enormous uncertainty for future investment. Currently there are more than a dozen separate regulations for $SO_2$ and $NO_x$ alone, and additional regulations are just around the corner. Adding mercury regulations to this already large and complicated list further complicates the operation and maintenance of coal-based assets. EPA needs to consider compounding issues as the agency moves through the regulatory process.

### C. Fuel Diversity and Infrastructure Should be Enhanced

The electric power industry is searching for ways to continue to produce low-cost electricity essential for global economic competitiveness. Federal policies should ensure the availability of an adequate and diverse fuel supply for the generation of electricity. Fuel diversity means that coal, nuclear, hydro, wind, solar, natural gas – and other fuel sources as they become available – can be used by generators of electricity to mitigate price or supply risk in any one source.

Policies advanced by the Congress and the Administration need to maximize the diversity of fuel sources available for the generation of electricity while allowing market forces to dictate the choice, in any given circumstance, of how to produce electricity at the lowest cost. This is one reason why a market-based cap-and-trade program for mercury makes sense.

A market of diverse generating technologies (coal, nuclear, hydroelectric and renewables as well as natural gas) supports fuel diversity and price stability. The price of converting different fuels to electricity varies by technology, but generally, the broader the selection of technologies and fuels available to the generator, the better for all classes of customers. When federal policies unnecessarily hinder the appropriate use of coal, the shortfall in generating capacity must be made up elsewhere. Carefully established policies that allow this abundant domestic fuel source to continue to play a serious role in the nation's fuel mix will help alleviate pressure on natural gas supplies.

Congress and federal agencies should be certain that federal energy, environmental and economic policies do not: (1) inadvertently create a policy climate wherein one fuel, such as natural gas, becomes the only practical option for new generation; (2) effectively preclude the use of abundant and low-cost fuels like coal; or (3) sharply limit the generators' flexibility to select a fuel mix that allows them to provide low cost power to consumers. Again, EPA needs to be mindful of fuel diversity when moving forward with the mercury rule.

## VI. CAP-AND-TRADE IS THE PREFERRED POLICY OPTION

EEI supports cap-and-trade as the preferred option for regulating electric power sector mercury emissions. EEI believes that EPA has the authority to establish a cap-and-trade program under either §111 or §112 of the CAA. EPA's MACT alternative would be far more expensive nationwide – yet less effective in reducing mercury emissions – than a national cap-and-trade approach. Analyses by EIA,[3] EEI,[4] and the Electric Power Research Institute (EPRI)[5] have shown that a command-and-control reduction program like MACT would be significantly more expensive than a cap-and-trade system achieving the same or similar levels of mercury emission reductions.

Should EPA pattern any trading program for mercury on the $SO_2$ elements of Title IV of the Clean Air Act and, where appropriate, the $NO_x$ SIP Call model trading rule. EPA should develop a federal trading program for mercury under §112(n)(1)(A) of the CAA. As part of a federal program under §112(n)(1)(A), EPA would allocate mercury allowances to sources in the same manner from state to state, regardless of which state

[3] "Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants," SR/OIAF/2001-04, Energy Information Administration, September, 2001.
[4] Economic analysis of the proposed mercury rule's options performed for EEI indicates that the MACT option would cost about $27.8 billion; the cap-and-trade option about $19.7 billion (NPV through 2020, 1999$).
[5] *A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies*. EPRI, Palo Alto, CA. TR-105224, 2003. This analysis indicates that for the same levels of reduction, a MACT costs about 3.5 times more than a cap-and-trade program.

a given source is located in. The topic of mercury allowance allocations is addressed in greater detail later in these comments.

**A. Regulatory Flexibility Through Emissions Trading is Imperative**

A multi-emission cap-and-trade program is the most cost-effective means to achieve substantial additional emission reductions from the power generation industry. A cap-and-trade program compels utilities to target reductions from the units where controls are most cost-effective, with a focus in almost all cases on the larger units with the highest emissions. This approach also provides the system-wide flexibility necessary to mitigate risk associated with trying innovative control technologies. Experience with the $SO_2$ allowance trading program under Title IV of the Clean Air Act demonstrates that an efficient cap-and-trade program will effectively deliver emissions reductions. Title IV delivered $SO_2$ reductions at a low cost to utilities and their customers far lower than initial estimates.

In its proposal, EPA acknowledges that regulation can achieve scientifically justified and verifiable mercury reductions and also provide electric utilities with flexibility. A cap-and-trade program does not allow a company to escape emission reductions; it merely allows those emission reductions to be made in a more cost-effective manner.

Trading should be allowed across the largest area possible to capture all possible efficiencies. Unfortunately, the proposed §111 approach could leave many issues subject to state-by-state variability and interpretation, which could result in a less efficient and comprehensive market-based program. It would also open the door for a limited trading market if numerous states choose not to allow affected sources in those states to participate. A shallow market might allow relatively few participants to influence allowance prices. In addition, a constrained market may lead to more conservative decisions by the electric utility industry with regard to installing emission controls, thereby driving up the cost of compliance. EPA should make every attempt to promote unfettered emissions trading in the final mercury rule.

### B. Emission Trading "Hot Spots"

#### 1. "Hot spots" do not exist

From a public health perspective, so-called mercury "hot spots" are areas with higher environmental mercury levels that could adversely affect public health. Some critics view emissions trading as "buying the right to pollute," expressing concern that emissions trading could cause increased levels of mercury in the local environment.

Based on many years of real-world experience, however, including studies of the acid rain allowance trading program conducted by EPA, the environmental group Environmental Defense and others, it is clear that trading did not significantly affect the pattern of where decreases in sulfur deposition actually occurred. The clear success of the acid rain $SO_2$ trading program provides reliable evidence to dispel fears about localized effects.

EEI believes there is no evidence of power plant-related mercury "hot spots" in the U.S. and associated increased risks to public health. Further, there is no scientific definition of a "hot spot." Various groups have posed varying interpretations of what a "hot spot" could be. For example, one possible interpretation of the term is an area having "heavy, localized [mercury] emissions and higher health risks."[6] EPRI defines a mercury "hot spot" as "a geographic location with total deposition of divalent mercury at levels that will result in mercury levels in consumable fish in underlying surface water drainages representing a potential for consuming women of childbearing age in the same state to exhibit mercury levels in blood exceeding the EPA Reference Dose equivalent."[7]

Others cite modeling work performed by EPA as a source of claims about mercury "hot spots." EPA's mercury deposition modeling was done using the REMSAD model which

---

[6] 69 Fed. Reg. 4703. The preamble to EPA's proposed rules offers a second interpretation of the terms, namely "that a power plant may lead to a hot spot if the contribution of the plant's emissions of Hg to local deposition is sufficient to cause blood Hg levels of highly exposed individuals near the plant to exceed the RfD." Ibid. at 4702.

[7] See comments by EPRI in this docket.

is a regional grid model. As detailed work by EPRI shows, regional grid models overpredict local effects.[8] There are three basic reasons for these overpredictions: (1) regional models deposit mercury to the ground closer to the source than a single-source plume model; (2) regional grid models do not include likely mercury reduction reactions in plumes which tend to reduce nearby mercury deposition, and (3) regional air models can only be verified against limited wet deposition data at moderate values. Such models consistently overestimate wet and dry deposition in areas where higher deposition rates are calculated; EPRI's work shows that regional air models can over predict local mercury deposition by factors of 2 - 4 due to the first reason alone, greater if the other reasons are considered.

### 2. The Florida everglades study is flawed

Some advocacy stakeholders and other commenters suggest that a report[9] released by the Florida Department of Environmental Protection in late 2003 demonstrates the existence of "hot spots" and further demonstrates that limiting mercury releases from coal-based power plants will cause rapid decreases in mercury concentrations in the local/regional environment. Neither conclusion can be defensibly drawn from the Florida report. While an extensive and valuable body of research has been conducted in south Florida, there are two major problems with how the results have been interpreted (both in the report itself and by others). First, to what degree has the relationship between local emissions reductions (which have decreased dramatically between the late 1980's and the early 1990's) and decreasing levels of mercury in biota (documented to have occurred between the early 1990's to present time, but not to the same degree everywhere in south Florida) been established, or put another way, how much of the latter was caused by the former? Second, to the extent we know this relationship, to what degree does it apply to coal-based power plants in other parts of the country?

---

[8] Ibid.

[9] "Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida: An approach for conducting a Total Maximum Daily Load analysis for an atmospherically derived pollutant," Florida Department of Environmental Protection, October, 2002 Revised November, 2003.

Regarding the first issue, while there some evidence about some relationship between local emissions reductions and local biotic response, the degree of the relationship has not been definitively quantified for the time period addressed by the Florida study. There is no deposition record spanning the time before and after the emission reductions modeled in the Florida study. Inferences from sediment cores are, at best suggestive, and at worst inconsistent. Second, while aquatic model hindcasting (currently being conducted) suggests a link between deposition and response in aquatic biota, it cannot allocate the share of deposition changes coming from other source changes and the share of the biotic response coming from non-depositional ecosystem changes (*e.g.,* hydrological, sulfate, phosphorous, dissolved organic carbon, etc.). To the extent that U.S. emissions reductions, European emissions reductions, and other worldwide emissions changes were affecting the changes in deposition at the same time (also a study in progress), it would moderate the degree that local emissions changes were having on deposition changes. Similarly, to the extent hydrological and other ecosystem changes were also affecting biotic mercury levels, these changes would moderate the role of local deposition. Finally, the atmospheric modeling conducted as part of the Florida Study was flawed in several ways. The modeling erroneously assumes that mercury deposition in waterways comes only from local sources. Modeling by EPA and EPRI has shown that more than 80 percent of the mercury that currently deposits in south Florida originates outside the U.S. While in the late 1980's it is likely that the local contribution was somewhat higher than it is today, it could not have been 100 percent. In summary, the magnitude of the connection between local emissions reductions in south Florida and local biotic response is tempered by the contributions from other emissions changes worldwide and other ecosystem changes affecting the biotic response.

On the issue of extrapolation, there are numerous arguments suggesting the results cannot be extrapolated to coal-based power plants in other areas of the country. Whatever relationship that may exist is unique to the type of emissions, the climatology, and the type of ecosystem that exists in south Florida. As previously discussed, research has yet to determine the magnitude of the connection between local emissions and local biotic responses. Second, municipal and medical waste incinerators – not power plants – are the source of industrial mercury emissions in south Florida referenced in the Florida report. Incinerators produce far higher percentages of ionic mercury – the form of mercury that is water-soluble and more readily deposited near sources – than coal-based power plants and have far shorter stack heights resulting in the potential deposition of higher amounts of mercury near these sources. Third, there is evidence that ionic mercury emissions from coal-based power plants rapidly convert to elemental mercury – the form of mercury having a long atmospheric residence time – a phenomena not observed in incinerators. This suggests that the link between emissions and local deposition would be less for coal-based power plants. Fourth, the climatology of south Florida is unique to the U.S. with daily, deep convective thunderstorms that converge over the Everglades in the summer. Fifth, the Everglades are not representative of U.S. waterways because they are in a subtropical zone with no distinct seasons and high rainfall in the summer, contain shallow water with very low flow rates, and bottom sediments that differ from those in other locations. Other waterbodies also have different levels of acidity, biological activity, dissolved oxygen, and turbidity. All of these differences can dramatically affect mercury cycling and uptake by biological organisms and make extrapolation of the Florida results to other areas of the country inappropriate. In summary, the extrapolation of the Florida study results to deposition or deposition to biotic response relationships, to other sources and areas of the country is inappropriate.

For these reasons, the Florida study cannot justify a conclusion by EPA that coal-based power plants create local "hot spots" nor can the results be extrapolated to coal-based power plants in other parts of the country.

### 3. Cap-and-trade will not create “hot spots”

Mercury “hot spots” will not be created by a cap-and-trade program. Cap-and-trade programs promote economically efficient decisions to reduce emissions from power plants. Units with the highest mercury emissions will be among the first to be controlled since the cost per pound of mercury controlled will be the lowest at these units. This economic behavior has previously been demonstrated in utilities' compliance with EPA's Acid Rain requirements[10] and the $NO_x$ SIP call.

Other facts suggest that localized effects will not occur with a mercury emissions trading program. Mercury emissions from utilities in the U.S. represent only a portion of emissions – approximately 20 percent of total North American emissions and about one percent of total global mercury emissions. In fact, current research indicates that North American anthropogenic sources were calculated to contribute only from 25-32 percent to the total mercury deposition over the continental U.S.[11]

To cite a specific example, a recent modeling study conducted to investigate the fate and transport of atmospheric mercury and its deposition in Michigan and the Great Lakes region found that mercury emissions from Michigan coal-based power plants contribute less than two percent to mercury deposition in northern Michigan and less than five percent to deposition in central and southern Michigan. Mercury emissions from Michigan coal-based power plants are calculated to contribute between 0.5 and 1.5 percent to total mercury deposition over each of the Great Lakes and about two percent statewide.[12]

Regulations or legislation will further reduce the relatively small contribution of power plant mercury emissions. A recent study[13] by EPRI found that reducing power plant generation mercury emissions will produce minimal benefits – a 47 percent cut would yield less than a one percent drop in human exposure. Even drastic reductions in utility mercury emissions will have a minimal effect on state fish advisories.

---

[10] "Swift Allowance Trading and Potential Hot Spots -- Good News from the Acid Rain Program," Environment Reporter, Vol. 31, No. 19, 954-959 (May 12, 2002).
[11] Seigner et al., "Global Source Attribution for Mercury Deposition in the United States," *Environ. Sci. Tech*. 38, 555-569, 2004.
[12] Vijayaraghavan et al., *Modeling Deposition of Atmospheric Mercury in Michigan and the Great Lakes Region*, Atmospheric & Environmental Research, Inc., March 2004.
[13] *A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies*. EPRI, Palo Alto, CA. TR-105224, 2003.

Newly completed modeling work performed by EPRI shows that mercury deposition will not increase in any area as a result of a cap-and-trade program.[14] This work indicates that when U.S. geographic locations are defined as "utility-influenced" or "non-utility influenced" based on whether 50 percent or more of the mercury depositing there is emitted from utility stacks, the utility-influenced locations together make up only 0.4 percent of the U.S. land area, and none of these areas are where the highest deposition occurs in the U.S. Even a mercury removal efficiency of 80 percent (which is what coal-based electric utility steam generating units will need to achieve to meet the 2018 cap of 15 tons[15]) will have a negligible change in deposition.

### 4. Most power plant mercury emissions will not deposit locally

Other research indicates that most power plant mercury emissions are of the elemental form soon after release, and therefore enter the global pool instead of depositing nearby. A recent study by Brookhaven National Laboratory found that only 4-7 percent of mercury is deposited locally (within 50 km). The study noted that "for the general population local deposition associated with the emissions from the coal-fired power plant were small," and that "estimated risks were more highly dependent on consumption patterns than increases in deposition due to coal-fired power plant emissions."[16]

Regulations to control $SO_2$ and $NO_x$ (*i.e.,* the CAIR proposal and other pending state and federal regulations) will require the installation of pollution controls that also will capture the forms of mercury that tend to deposit nearby. The species of mercury that are deposited locally – oxidized and particulate mercury – are controlled by the same equipment that controls $SO_2$ and $NO_x$ and particulates.

[14] See comments submitted by EPRI in this docket.
[15] EPA and UARG have estimated from the Part 2 ICR data that approximately 75 tons of mercury was contained in the coal burned by power plants in 1999. The 2018 cap of 15 tons requires an 80 percent removal of mercury from this input amount.
[16] Sullivan, et al., *Assessing the Mercury Health Risks Associated with Coal-Fired Power Plants: Impacts of Local Depositions*, Brookhaven National Laboratory, May, 2003.

Finally, the economics of trading will help to minimize local deposition. The trading of allowances almost always involves large coal-based power plants controlling their emissions more than required, to the extent possible, and selling allowances to smaller plants. Thus, economies of scale of pollution control investment will favor investment at the larger plants and will produce reductions in emissions at the plants of greatest interest.

## VII. HEALTH EFFECTS OF MERCURY FROM POWER PLANTS HAVE NOT BEEN DEMONSTRATED

Again, EEI acknowledges that mercury in the human body, at high enough levels, can cause adverse neurological and developmental effects. EEI and its members share the goal of protecting public health and are prepared to make reasonable additional reductions in power plant mercury emissions. We believe, however, that the reductions should be made commensurate with the health risks that are to be addressed by the rule.

### A. EPA Acknowledges Uncertainties in Assessing Health Risks

In its December 2000 regulatory determination, EPA noted "there are uncertainties regarding the extent of the risks due to electric utility mercury emissions." Previously, in its *Mercury Research Strategy*, EPA stated that "[t]he amount of mercury deposited in the United States that can be directly attributed to domestic combustion sources remains uncertain."[17] Three years later, after extensive research on the fate and transport and atmospheric chemistry of mercury, EPA stated in the proposed mercury rule that the agency "cannot currently quantify whether, and the extent to which, the adverse health effects occur in the populations surrounding these facilities, and the contribution, if any, of the facilities to those problems." Further, in addressing the state of the science, the proposed rule notes that "the relationship between Hg emission reductions from Utility Units and methylmercury concentrations in fish cannot be

[17] "Mercury Research Strategy," EPA/600/R-00/073, Environmental Protection Agency, September, 2000.

calculated in a quantitative manner with confidence." Finally, EPA admits that "[t]he Agency is unable to provide a monetized estimate of the benefits of Hg (mercury) and Ni (Nickel) emissions reduced by the proposed rule at this time."

Given these uncertainties, any policy that seeks to regulate electric utilities' mercury emissions should take into account technical feasibility, cost, and impacts on generating, transmitting, and distributing electricity in an affordable and reliable manner. EEI acknowledges that EPA's January 30 proposal recognizes that regulation can achieve verifiable reductions in mercury emissions, but they need to be achieved in a manner that also provides electric utilities with flexibility and minimizes economic and potential electric reliability effects.

### B. Health Benefits of Eating Fish

In the January 30 proposal EPA states, "Given the current scientific understanding of the environmental fate and transport of this element, it is not possible to quantify how much of the methylmercury in fish consumed by the U.S. population is contributed by U.S. emissions relative to other sources of Hg (such as natural sources and reemissions from the global pool)."[18] Recognizing this fact and noting the health benefits of eating fish, EPA further acknowledges, "The typical U.S. consumer eating a wide variety of fish from restaurants and grocery stores is not in danger of consuming harmful levels of methylmercury from fish and is not advised to limit fish consumption." Several public health organizations concur with this assessment.

The American Medical Association (AMA) acknowledges that "fish is part of a nutritious diet and is a particularly good source of high-quality protein and essential fatty acids as well as being low in saturated fat."[19] The AMA also states that "because of the wide

[18] 69 Fed. Reg. at 4658.
[19] Schober et al., "Blood Mercury Levels in U.S. Children and Women of Childbearing Age 1999-2000," JAMA 289(13):1667-1674.

variations in the concentrations of mercury in fish and shellfish, it is possible to have the nutritional benefits of moderate fish consumption and avoid fish high in mercury."[20]

The EPA and Food and Drug Administration (FDA) note that fish and shellfish can be important parts of a healthy and balanced diet, are good sources of high-quality protein and other nutrients, and are low in fat. The agencies recommend that women who are pregnant, planning to become pregnant, nursing mothers, and young children modify the amount and type of fish they consume. The EPA and FDA note that following their fish consumption guidelines will give consumers the positive benefits of eating fish while avoiding any problems from mercury in fish.[21]

The American Heart Association (AHA) states that "consumers need to be aware of both the benefits and risks of fish consumption for their particular stage of life."[22] The AHA recommends consuming a wide variety of fish species within the guidelines set by EPA and FDA as the best approach to both minimizing risks and increasing benefits of eating fish.

In the Seychelles Child Development Study,[23] which has followed 779 mother-infant pairs residing in the Republic of Seychelles, the authors report that "These data do not support the hypothesis that there is a neurodevelopmental risk from prenatal MeHg exposure resulting solely from ocean fish consumption." The study notes that "The most common form of prenatal exposure is maternal fish consumption, but whether such exposure harms the fetus is unknown." It is interesting to note also that mothers reported consuming fish on average 12 meals per week, a much higher level than is common in the U.S. In assessing the import of the Seychelles' results, in the same Journal as the study, Constantine G. Lyketsos of Johns Hopkins Hospital sums up the public health implications:

[20] Ibid.
[21] *What You Need to Know About Mercury in Fish and Shellfish*, U.S. Environmental Protection Agency and U.S. Food and Drug Administration, March 2004.
[22] Fish Consumption, Fish Oil, Omega-3 Fatty Acids and Cardiovascular Disease, Circulation, Journal of the American Heart Association, 106:2747-57.
[23] Myers et al., "Prenatal methylmercury exposure from ocean fish consumption in the Seychelles child development study," Lancet 2003; 361: 1686–92.

"On balance, the existing evidence suggests that methyl mercury exposure from fish consumption during pregnancy, of the level seen in most parts of the world, does not have measurable cognitive or behavioural effects in later childhood. This conclusion is especially true against the background of the several other variables that affect cognitive-behavioural development. The positive findings from the Faeroe Islands and New Zealand studies may be related to the fact that pilotwhale blubber and shark muscle contain 5-7 times the concentrations of methyl mercury than the fish consumed in the Seychelles. While higher concentrations in seafood do not necessarily lead to higher levels in maternal hair, consumption of much larger boluses by the mother could lead to greater difficulty on the part of the developing fetus to detoxify the mercury by natural mechanisms, as Meyers and colleagues propose. Whatever the answer, the discrepant findings from the various studies need explaining. Whilst there is always an issue of power to detect an effect in a study reporting null findings, this is not likely to be the case in the Seychelles study with the sample size involved. If there is subtle association that could only have been detected in a much larger sample or through the use of more sensitive tests, it can reasonably be argued that the effect would be small enough to be essentially meaningless from the practical point of view. For now, there is no reason for pregnant women to reduce fish consumption below current levels, which are probably safe."[24]

### C. Eliminating Mercury Emissions From U.S. Utilities Will Not Change Fish Advisories

Even if one were to eliminate mercury emissions from U.S. utilities (which is impossible) it would likely lower exposure to mercury among U.S. residents only slightly because other factors affect mercury in the U.S. food supply. Only some U.S. anthropogenic emissions are from utilities. Utilities in the U.S. release about 48 tons per year, about 40

[24] Lyketsos, C., "Should pregnant women avoid eating fish? Lessons form the Seychelles," *Lancet* 2003; 361: 1667-1668.

percent of domestic anthropogenic emissions and about one percent of total global mercury emissions. Recent research in which global mercury emissions and deposition patterns were modeled shows that "North American anthropogenic sources were calculated to contribute only from 25 to 32% to the total mercury deposition over the continental United States." This same research notes that "Asian anthropogenic emissions were calculated to contribute from 5 to 36% and that natural emissions were calculated to contribute from 6 to 59%."[25]

Although there is general scientific agreement that atmospheric mercury has many natural and anthropogenic sources, to date there is no scientific consensus on the relative amount each category of emission source contributes to mercury deposition at local, regional, and global scales. In addition, examination by the U.S. Geological Survey (USGS)[26] of ice core samples in the U.S. indicates that over a 270-year period there were large changes in mercury deposition due to variation in both natural and anthropogenic sources, and that there are regional-to-global scale impacts from natural mercury sources (*e.g.,* one can easily see a mercury deposition spike from the Krakatau volcano explosion in 1883 – a spike that exceeds any maximum since industrialization began in earnest in the year 1900 (excluding the huge spike from Mt. St. Helens' eruption in 1980)).

Field measurements of mercury fluxes from naturally mercury-enriched areas suggest that regionally, natural emissions are orders of magnitude higher than previously thought. For example, a recent study of long-range transport of gaseous mercury in a smoke plume from a series of boreal forest fires in northern Quebec concludes that "[a]nnual Hg emissions from boreal fires in Canada may equal 30% of annual Canadian anthropogenic emissions in an average fire year and could be as high as 100% during years of intense burning."[27]

---

[25] Seigner et al., "Global Source Attribution for Mercury Deposition in the United States," *Environ. Sci. Tech.* 38, 555-569, 2004.
[26] Krabbenhoft and Schuster, 2002, "Glacial Ice Cores Reveal A Record of Natural and Anthropogenic Atmospheric Mercury Deposition for the Last 270 Years: 2002 U.S. Geological Survey Fact Sheet" FS-051-02.
[27] "Emission and Long-Range Transport of Gaseous Mercury from a Large-Scale Canadian Boreal Forest Fire," *Environ. Sci. Tech*. 37, 4343-4347, 2003.

Despite recent research about how mercury is methylated in waterbodies and enters the food chain,[28] there is no accepted quantitative estimate of the relationship between mercury deposition and mercury concentrations in fish. EPA noted in its December 2000 regulatory determination only a "plausible link" between the two. To better understand this relationship, a comprehensive study (the METAALICUS[29] project) has been underway to better understand the transport, behavior and fate of mercury in lake ecosystems with an emphasis on the response of mercury cycling to changes to atmospheric mercury deposition. According to a recent update on this work,[30] a key uncertainty limiting the ability to predict the effects of changing atmospheric mercury deposition on fish mercury concentrations is the role of inorganic mercury loading/supply on methylation.

Over the past decade, much has been learned about the behavior of mercury in the aquatic environment. Several facts regarding the process of methylation have become generally accepted, including:[31]

- Mercury in various forms enters water bodies from terrestrial, aquatic, and atmospheric sources.
- Sulfate and sulfide are now known to play a complex role in methylation of mercury, with sulfate stimulating methylmercury formation at low levels, and sulfide inhibiting formation of methylmercury at high sulfide levels.[32] Other abiotic factors of significance in mercury methylation in aquatic environments include dissolved organic carbon and pH.

---

[28] Mason et al., "Uptake, Toxicity, and Trophic Transfer of Mercury in a Coastal Diatom," *Environ. Sci. Technol.* 30, 6. U.S. EPA, *Mercury Study Report to Congress, Volumes I to VIII.* EPA-452/R-97-03, Washington, D.C.: U.S. Environmental Protection Agency.

[29] Mercury Experiment To Assess Atmospheric Loading In Canada and the United States – this program involves international, federal and state bodies and private and public research organizations in the U.S. and Canada.

[30] *Atmospheric Mercury Research Update*, EPRI, Palo Alto, CA: 2004. 1005500.

[31] Ibid.

[32] Benoit et al., "Sulfide Controls on Mercury Speciation and Bioavailability to Methylating Bacteria in Sediment Pore Waters," *Environ. Sci. Tech*. 33:951-957.

Benoit et al., "The influence of sulfide on solid phase mercury bioavailability for methylation by pure cultures of Desulfobulbus propionicus (1pr3)," *Environ. Sci. Tech*. 35:127-132.

- The bioaccumulation of methylmercury in aquatic organisms, in particular fish, is primarily a function of interacting factors, including the rate of introduction of new inorganic mercury into the system, the net mercury methylation rates, food web length, and total mass.

Indeed, the process of methylation is very complicated. Though much has been learned through field research, much uncertainty still exists. Moreover, available statistical evidence does not show a positive association between mercury concentrations in fish and mercury deposition. Concentrations of methylmercury in fish vary significantly and are dependent on four factors: 1) the trophic level of the fish (level of the fish in the aquatic food web); 2) age of the fish; 3) whether the fish is wild or farm-raised; and 4) whether the fish is a freshwater, marine, or estuarine species.[33]

Even if there were a straightforward correlation between mercury deposition and mercury in fish, computer models run by EPA and by EPRI similarly have shown that a relatively large change in power plant mercury emissions resulted in only slight changes in deposition nationally (in one study, a 47 percent cut in emissions results in a 3 percent drop on average in deposition).[34]

Mercury deposition in the U.S. affects only a small portion of fish consumed by U.S. residents. Mercury levels in marine fish from distant waters and in farmed fish that eat commercial feed are not sensitive to changes in U.S. emissions. Even mercury levels in seafood caught near the U.S. may be relatively insensitive to local deposition, because of the complexity and geographic extent of marine food chains. Growing evidence suggests that most exposure to mercury, even among populations with high fish intake, comes from consumption of seafood caught in offshore waters where reductions in U.S. mercury emissions will have negligible impact.[35] These fish are predominantly from waters unaffected by U.S. emissions. Determining how much of the mercury exposure

[33] Weiner, et al., "Ecotoxicology of Mercury," *Handbook of Ecotoxicology*. New York:Lewis Publishers, 409-63.
[34] *A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies*. EPRI. Palo Alto, CA. TR-105224.
[35] U.S. EPA, *Mercury Study Report to Congress*, Vol. IV, pp. 4-37.

among "highly" exposed individuals is sensitive to changes in U.S. deposition is largely subjective, because there is no assessment of how much of such exposure comes from different types of fish (*e.g.,* from distant oceanic fish vs. locally-caught fish). Furthermore, recent evidence suggests that mercury levels in oceanic fish are insensitive to changes in man-made mercury emissions,[36] implying that mercury levels in oceanic fish are controlled by deep ocean processes that we have yet to understand.

Most Americans, however, eat very little fish. Half of all Americans eat no fish whatsoever and, of those who do the weekly average consumption is about one-quarter pound. [37] Nearly all of this fish is storebought ocean fish, which is unlikely to contain much mercury emitted from U.S. sources. On average, less than 10 percent of fish eaten in the U.S. comes from wild U.S. freshwater sources, although some anglers and others may consume larger amounts.

### D. There is Little Actual Exposure to Methylmercury in the U.S.

Of the fish that Americans do eat, the average concentration of mercury in the types of fish commonly purchased in stores is less than 0.3 ppm, the level of the EPA criterion (and much less than the FDA advisory level of 1.0 ppm). Canned tuna has an average mercury concentration of 0.17 ppm, or one-half of the EPA criterion.

Recent and comprehensive research undertaken by the Centers for Disease Control and Prevention (CDC), which measured mercury in the blood of women, indicates that people in the U.S. are not being exposed to levels of mercury considered to be harmful to fetuses, children, or adults. According to the CDC, "The levels reported in this NHANES [National Health and Nutrition Examination Survey] 1999-2000 subsample for maternal-aged females were below levels associated with *in utero* effects on the fetus, or with effects in children and adults (National Academy of Sciences, 2000)."[38]

[36] *See* Krapiel et al. in *Environ. Sci. Tech*. 37:5551-5558, 2003.
[37] *Frequently Asked Questions About Mercury*, Electric Power Research Institute, December 22, 2003.
[38] *Second National Report on Human Exposure to Environmental Chemicals*, Centers for Disease Control and Prevention, National Center for Environmental Health, Pub. No. 02-0716, Revised March 2003.

When the NHANES data are weighted to account for U.S. demographic patterns, about 7.7 percent of women in the study have blood levels of methylmercury above 5.37 ppb,[39] the blood concentration associated with the EPA reference dose (RfD). However, NHANES data variability appears to preclude accurate prediction of an individual's blood level of mercury based on fish consumption.

In 2003, the World Health Organization (WHO) revised its recommendation for safe intake levels for mercury in food to 1.6 μg/kg of body weight/week. This revised reference dose for mercury adopted by WHO is more than two times higher (less stringent) than EPA's reference dose (0.1 μg/kg of body weight/day). EPA's reference dose – which was reaffirmed by EPA in 2001 – is lower due to the inclusion of an extremely conservative safety factor of 10. If the NHANES data were compared to the WHO level, no one in the U.S. would be close to exceeding the safe intake level. In communicating its revised limits, WHO noted that "public health authorities should keep in mind that fish play a key role in meeting nutritional needs in many countries."[40]

## VIII. STATUS OF CONTROL TECHNOLOGIES

### A. Overview

Reliable, cost-effective control technologies designed specifically for capturing mercury have not yet been fully developed or tested. EPRI, DOE, and EPA have conducted extensive R&D programs over the past decade with the objective of developing cost-effective methods for reducing power plant mercury emissions. Of the various options under investigation, one is to inject materials – such as activated carbon – into flue gases to adsorb or react with mercury and produce solids that can subsequently be captured by particulate control devices. Another method is to inject chemicals into the boiler, or insert structures coated with catalysts into the flue gas, to produce compounds of mercury that can be captured by $SO_2$ controls. One such structure may involve the

[39] Schober et al., "Blood Mercury Levels in U.S. Children and Women of Childbearing Age 1999-2000," JAMA 289(13):1667-1674.
[40] WHO Press Release, "UN Committee recommends new dietary intake limits for mercury," June 27, 2003.

catalysts used for $NO_x$ control in selective catalytic reduction (SCR) systems. Current tests are determining how and under what conditions these catalysts can produce the water-soluble form of mercury that can be captured by $SO_2$ controls. Another approach is attempting to adsorb the mercury onto solid structures placed in the flue gas stream.

As noted earlier, mercury control technology capable of achieving high removal rates (*i.e.,* greater than 80 percent) across the entire industry is not available. Full-scale demonstrations of mercury control technologies at individual power plants are just getting underway. It will take at least 2 to 3 years to complete these initial demonstrations and evaluate the potential effectiveness of possible new control technologies. And then, several more years will be needed before these technologies can be considered "commercially available."

### B. Co-Benefits and Current Technologies

#### 1. "Co-benefits" as defined in the proposed rule

The mercury proposal recognizes that reliable, cost-effective control technologies designed specifically for capturing mercury from coal-based power plants are not yet commercially available. EPA, DOE, and others are in agreement that implementing further controls for reducing $SO_2$ and $NO_x$ as required in the proposed CAIR will, it is to be hoped, result in additional reductions – "co-benefits" – in mercury emissions.

In the proposed rule's cap-and-trade alternative, EPA proposes to set a near-term cap in 2010 at a level that reflects the maximum reduction in mercury emissions that could be achieved through the installation of FGD and SCR units that will be necessary to meet the 2010 caps for $SO_2$ and $NO_x$ in the proposed CAIR.[41] This is how EPA intends to define "co-benefits." Questions remain, however, as to the extent to which "co-benefits" of reductions in mercury emissions that will be provided by these $SO_2$ and $NO_x$

[41] 69 Fed. Reg. 4698 (Jan. 30, 2004).

controls. EPA is therefore requesting comment and specific technical information concerning the “co-benefits” number for the first phase cap level in 2010.

### 2. “Co-benefits” from existing controls

It is possible to obtain some level of mercury control as a “co-benefit” of FGD systems (or scrubbers) designed to control $SO_2$ emissions, perhaps in combination with SCR technology designed to control $NO_x$ emissions. In fact, current air pollution control technologies being used to reduce particulates, $NO_x$ and $SO_2$ emissions from coal-based power plants in the U.S. already capture, on average, about 40 percent of the 75 tons of mercury that enters the boilers with the coal. However, the removal rate of mercury for any particular plant can vary from zero to over 90 percent, depending on the type of coal and the air pollution control devices used and other factors. A major difficulty lies in successfully capturing the two gaseous forms of mercury: elemental and ionic. The difference between the two being that ionic is water soluble and elemental is not. The design of the boiler and combustion system, the chemical form of the mercury produced, the properties of the fly ash, the presence of other chemicals and the relatively low concentration of mercury in flue gas all impact how much mercury removal is achieved.

One possible cause of this large variation in mercury capture is that speciation of mercury in power plant flue gas can vary significantly from plant to plant depending on coal properties and combustion conditions. Mercury in flue gas exists in one of three forms: elemental, ionic, or particulate. The proportions of the three chemical forms of mercury have a great influence over the behavior of the mercury in the flue gas and therefore the degree of reduction possible.

In short-duration tests of the various pollution controls currently installed throughout the fleet of U.S. coal-based power plants, mercury reductions have ranged from zero to 99 percent. Maximum removals across different controls are about 50 percent for cold-side ESP, 80 percent for FFs, 70 percent for cold-side ESP followed by a wet FGD, and greater than 95 percent for a spray dryer FGD combined with a FF. Levels are substantially lower in many cases for subittuminous and lignite coals.[42]

As the wide differences in removal indicate, many challenges and obstacles exist to mercury removal from the diverse fleet of coal-based generating units in the U.S. The complex mercury chemistry coupled with a lack of data on the chemical reactions which occur in the flue gas greatly hinder the understanding of how to effectively control mercury emissions.

### a. mercury co-benefits with FGD

One of the most important factors in determining the efficiency of mercury capture appears to be the form of the mercury in the flue gas that enters the scrubber. Ionic mercury tends to be soluble in water and is captured along with $SO_2$, while elemental mercury, being insoluble in water, passes through most of the scrubber processes and escapes out the stack. Wet FGD units currently installed on about 25 percent of coal-based power plants in the U.S. remove about 80-95 percent of gaseous ionic mercury but virtually none of the elemental mercury.[43] The mercury reduction by $SO_2$ control processes is, therefore, dependent on the fraction of ionic mercury in the flue gas.

In many cases, the form of the mercury in the flue gas appears to be influenced by the chlorine content of the coal. Coals with high chlorine levels tend to produce flue gas that is typically higher in ionic mercury. The rank of the coal is a good predictor of chlorine content. A majority of coal found in the eastern U.S. is bituminous coal. Most of the coal found in the western U.S. is either subbituminous or lignite, however, bituminous coal is found in Colorado and New Mexico. Almost all of the coals found in the western U.S. have a characteristically-low chlorine content. The fraction of ionic mercury, and consequently the level of mercury captured in a scrubber, will be much higher for eastern coals than for western coals.

---

[42] Pavlish et al., “Status review of mercury control options for coal-fires power plants,” *Fuel Processing Technology* 82(2003) 89-165.
[43] Ibid.

Notwithstanding the ability of $SO_2$ control processes to capture mercury, there may be a problem with capturing mercury in wet scrubbers. At some power plants with wet scrubbers that were tested for mercury species, the high capture rate of ionic mercury was offset by an increase in the amount of elemental mercury found in the flue gas exiting the scrubber. It seems that some of the ionic mercury is converted back to its elemental form and escapes from the scrubber through the stack after being captured in the scrubber. This scrubber mercury re-release is not yet well understood. Analysis of the phenomenon indicates that this effect is present at some times, and not at others, indicating that the overall capture of mercury by a wet scrubber is inconsistent and less over time than what the short test periods to date might indicate.

Another process for $SO_2$ control, used for low-sulfur western coals, is a lime-based spray dryer followed by a fabric filter (FF) that collects the reacted lime along with the coal ash. This technology is only effective for $SO_2$ control from low-sulfur coals, and is seldom used. In addition, it is more expensive for high-sulfur coal than alternative technologies. This spray dryer/FF FGD process may be more efficient at removing mercury from bituminous coals, and may be used in a few power plants burning eastern bituminous coal for combined $SO_2$ and mercury control, but wide use is not expected.

### b. mercury co-benefits with SCR

It has been conjectured since the mid-1990s that SCR installed for $NO_x$ reduction could significantly increase the oxidation of mercury in the flue gas. Thus, a coal-based power plant equipped with SCR upstream of FGD could potentially achieve significant removal of mercury from the flue gas. Based on a report from a German utility[44] claiming that SCR catalyst was extremely effective in converting elemental mercury to the ionic form, EPA concluded that any power plant with this combination of pollution controls, burning any type of coal, would have nearly all of the elemental mercury converted to ionic mercury; that almost all of the ionic mercury would be captured in a scrubber, with no

[44] Guberlet et al., *SCR Impacts on Mercury Emissions on Coal-fired Boilers*. Presented at EPRI SCR Workshop, Memphis, TN, April 2000.

mercury re-released from the FGD process; and that this combination would uniformly result in an estimated 95 percent reduction in overall mercury emissions.

Tests during the last several years at operating power plants have shown that these assumptions are rarely true. Changes in mercury speciation are dependent on operating temperature, the concentration of ammonia and chlorine in the flue gas, the gas velocity, a function of the chemical composition of the coal, and are coal-specific.

In addition, it is known that an SCR catalyst's ability to remove $NO_x$ diminishes over time; a catalyst typically must be replaced every three to five years when the SCR is being run seasonally. Exposure to flue gas degrades catalytic activity, as ash particles plug the catalyst surface and chemicals in the flue gas damage the catalyst's active ingredient. It is not known how this process may affect a catalyst's ability to oxidize mercury or how mercury in the flue gas would affect catalyst performance. Only limited testing has been performed to date in order to assess the effect of SCR catalysts in oxidizing mercury in the flue gas.[45]

It should be noted that under CAIR, SCR would need to be operated continuously in order to control mercury, and this could further decrease catalyst performance. Any estimate of the long-term potential for the co-benefits of SCR and FGD for mercury reduction must consider the possibility of catalyst aging and the subsequent potential loss in mercury oxidation and $NO_x$ removal.

SCR mercury oxidation does not appear to occur when low-rank western coals are burned.[46] The low chlorine content and alkaline ash typical of low-rank coals may cause the small amount of oxidizing chlorine present in the flue gas to be neutralized by the fly ash before it reaches the SCR catalyst. The majority of the mercury found in the flue gas from western coals will remain in the elemental form even if an SCR is present,

---

[45] Chu et al., *Power Plant Evaluation of the Effect of SCR Technology on Mercury*. Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19-22, 2003.
[46] *Impact of SCR on Mercury Speciation*, EPRI. Palo Alto, CA. TR-1004269, December, 2003, pp. 19-22.

therefore the addition of an SCR will not significantly improve the control of mercury emissions for plants burning low-rank coals. Co-benefits from an SCR/FGD combination for lignite and subbituminous coals will be much less than for bituminous coals.

### 3. Limitations of current technologies

A consensus of what is known about the limitations and ability of FGDs and SCRs to achieve mercury "co-benefits" reductions was summarized in a recent review of the DOE/NETL mercury control technology research program:[47]

- Coal properties (*e.g.,* chlorine and sulfur content, ash characteristics) greatly influence the ability of existing pollution control technologies to capture mercury.
- FGD systems have been successfully demonstrated to capture oxidized (ionic) mercury. Potential reduction of a portion of the oxidized mercury to elemental mercury within the wet FGD may reduce overall capture in some applications.
- Although mercury oxidation across SCRs has been demonstrated, it appears to be highly variable depending on coal properties and SCR catalyst factors including type, sizing, and age.
- Uncertainties remain regarding mercury capture effectiveness with different coal ranks and existing pollution control device configurations, and balance-of-plant impacts.
- Significant variability in mercury capture co-benefits of existing pollution controls has been observed at similar units as well as at individual units tested at different times, even while burning the same coal.

## C. Future Controls: Sorbent Injection

The most promising mercury-specific control technology developed to date is activated carbon injection (ACI). There have been only a handful of tests of the use of activated

[47] Feeley, et al., *A Review of DOE/NETL's Mercury Control Technology R&D Program for Coal-Fired Power Plants*, U.S. DOE, National Energy Technology Laboratory, April 2003.

carbon to control mercury emissions from coal-based power plants.[48] All test sites are somewhat unique and, unfortunately, are not typical of the nation's power plant fleet. Testing is also actively underway using other sorbent injection technology as well as other applications such as oxidation catalysts and boiler injection.

Recent, as yet unpublished research discussed in EPRI's comments casts doubt on whether high removal rates can be achieved from all eastern coals. Arcing has occurred in some precipitators in recent ACI injection tests. Additionally, units with small precipitators may not properly remove particulate matter if their performance is substantially degraded by ACI injection. The ability of small precipitators to continue to perform properly when subjected to ACI injection is the subject of a substantial DOE research effort this year.

Research to date indicates that an average removal efficiency across the industry will be much less than 90 percent, especially considering that the best results from subbituminous coals have shown lower removal rates than the best results from bituminous coals. Research with lignite coals shows that the much higher temperatures lignite plants operate at than other ranks interferes with the mercury-carbon reaction, impeding its capture and removal.

One potential problem with ACI is that the current supply of activated carbon is not sufficient to accommodate a substantial demand from the utility sector and it could take up to five years to bring new activated carbon production facilities on line.[49]

A recent EPA report (*Control of Mercury Emissions from Coal-Fired Electric Utility Boilers*, March, 2004) outlines several efforts that are needed in order to enhance the

[48] Lindsey et al., *Results of Activated Carbon Injection Upstream of Electrostatic Precipitators for Mercury Control*. Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19–22, 2003.
Bustard et al., *Results of Activated Carbon Injection for Mercury Control Upstream of a COHPAC Fabric Filter.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19–22, 2003.
[49] Monroe, Larry. "The Status of Mercury Control Technology," *EM* October 2003, 26-31.

cost effective capture of mercury by ACI, and other sorbent injection systems. EEI agrees with the conclusions in the report:

> "A very limited set of short term full-scale trials of activated carbon injection have been carried out as described earlier in this white paper. These trials do not cover a representative range of control technology/fuel combination that would be required to demonstrate the widely achievable levels of Hg control that might be achieved in a cost effective manner. Furthermore, they represent short-term (4-9 day) continuous operation and do not address all of the operational issues and residue impacts that may be associated with commercial operation. Therefore, these technologies are not currently commercially proven to consistently achieve high levels of Hg control on a long-term basis."

**D. Coal Combustion Products**

One settled issue regarding mercury removal from power plant emissions is the regulatory status of the combustion residues where FGD or other existing systems are the mercury emission control device. These residues, known as coal combustion products (CCPs), may contain trace amounts of mercury and contain other constituents captured by existing emission controls. In 1980, Congress passed the Bevill Amendment to the Resource Conservation and Recovery Act (RCRA) (42 U.S.C. § 6901 *et seq.*) which exempted CCPs (*i.e.,* fly ash, bottom ash, boiler slag, and flue gas emission control material) from hazardous waste regulation under Subtitle C of RCRA pending a detailed and comprehensive study by EPA of any potential adverse health and environmental effects associated with the disposal and use of CCPs.[50] EPA studied the risks associated with CCPs (including the potential release of mercury and other constituents from the use and disposal of CCPs) and reported to Congress that CCPs do not warrant regulation as hazardous waste.[51] Based on the findings in these reports,

[50] *See* 42 U.S.C. § 6921(b)(3), codifying a portion of the Bevill Amendment.
[51] *See* EPA, Report to Congress on Waste from the Combustion of Coal by Electric Utility Power Plants (March 8, 1988); EPA, Report to Congress on Waste from the Combustion of Fossil Fuels (March 31, 1999).

EPA concluded, among other things, that CCPs do not warrant hazardous waste regulation under RCRA.[52]

In its 2000 regulatory determination, EPA left open the possibility of regulations to address potential risks from elevated levels of constituents in CCPs captured by future mercury controls. EPA acknowledged that there was insufficient information to determine the characteristics and potential risk associated with the wastes generated by future air emission controls.[53] In the meantime, therefore, CCPs generated by plants that employ ACI or some other new flue gas emission control system to reduce mercury emissions will remain exempt from federal hazardous waste regulation until there is evidence of significant change in the characteristics and potential risks of the CCPs and EPA concludes, in accordance with the requirements of the Bevill Amendment, that revision of the prior regulatory determination is necessary.[54]

### E. Summary

In a comprehensive analysis[55] of mercury control technologies summarizing what has been learned to date regarding mercury emission control technology approaches, EPRI draws the following conclusions:

- Research results to date indicate that a number of uncertainties create difficulties in quantifying mercury removals and in identifying factors that impact these removals.
- Two considerations are important in the analysis of specific mercury control technology alternatives: 1) recognition of the appropriate chemical composition of mercury species at the point of capture, and 2) an understanding of the implications of the various chemical analysis methods is necessary to accurately evaluate control test results and to understand the appropriateness of a given technology.

---

[52] *See* 58 Fed. Reg. 42466, 42472 (Aug. 9, 1993); 65 Fed. Reg. 32214, 32215 (May 22, 2000).
[53] *See* 65 Fed. Reg. at 32220-21, 32225.
[54] *See* ibid. at 32225; 42 U.S.C. § 6921(b)(3)(A), (C) (hazardous waste regulation of Bevill wastes is permissible only after a comprehensive EPA study of the waste, a report to Congress containing EPA's findings and recommendations, a public hearing and notice and comment rulemaking procedures, and a regulatory determination based on the study and rulemaking).
[55] *Atmospheric Mercury Research Update*, EPRI, Palo Alto, CA: 2004. 1005500.

- On average, the lower the coal rank, the lower the mercury emissions reductions achievable; however, mercury emissions reductions may also vary within a given coal rank.
- Control technologies that reduce $SO_2$, $NO_x$, and PM for coal-based plants yield levels of mercury control ranging from 0 to over 90 percent, depending on boiler design, and emission control equipment. For Powder River Basin (PRB) coal mercury capture with an ESP is 0-30 percent; plants with baghouses average 50-60 percent with some removal rates as high as 90 percent based on short-term testing.
- Oxidation of mercury in SCRs is affected by the coal type and catalyst design with the extent of oxidation higher for Eastern bituminous than Western coals.
- ACI is the most investigated option for mercury removal, for most plants equipped with an ESP or baghouse. Tests to date indicate that flue gas chloride and $SO_2$ content are key components that affect ACI performance. Mercury removal effectiveness appears to be quite variable and influenced by a number of variables that are still being investigated.
- Emerging control technologies for mercury are under development and demonstration, but are not commercially deployed.

## IX. COMMENTS ON MERCURY PROPOSAL

### A. Cap-and-Trade vs. MACT

Section 112(n)(1)(A) of the CAA provides EPA broad authority to craft regulation of electric utility steam generating units to address any health concerns EPA identifies in its Utility Study.[56] Section 112(n)(1)(A) requires EPA to "regulate electric utility steam electric generating units under this section if the Administrator finds such regulation is appropriate and necessary." The provision also instructs EPA to develop alternative control strategies for emissions that may warrant regulation. Possible control strategies

[56] "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress," EPA-453/R-98-004a, February 1998.

include a cap-and-trade program, risk-based standards, MACT limits or some hybrid form of these approaches.

EEI believes that a cap-and-trade program provides the best framework for achieving the greatest amount of mercury reductions from coal-based power plants in the most economically efficient way. Cap-and-trade programs promulgated under the CAA Acid Rain provisions and the $NO_x$ SIP call have proven highly successful in reducing air pollutant emissions. A similar program would work equally well in reducing mercury emissions from coal-based power plants.

Mercury emissions should be understood in their global context. As noted above, over 70 percent of the mercury that deposits in the U.S. comes from sources outside the U.S. EPRI modeling work predicts that reducing total mercury emissions from coal-based power plants by more than two-thirds to 15 tons annually will reduce mercury deposition in the U.S. by only 6.9 percent – from 165.4 tons per year to 153.9 tons per year. Based on the results of this state-of-the-science mercury transport and fate modeling, it would be more sensible – and better public policy – for EPA to set limits on total annual mercury emissions and then allow utilities to determine how best to achieve those reductions, instead of imposing command-and-control MACT requirements on every coal-based plant.

We agree with EPA's choice of a cap-and-trade program as the preferred alternative to MACT. As demonstrated through EPA's Acid Rain program, a well constructed cap-and-trade program can achieve significant emission reductions in a cost-efficient manner. A cap-and-trade program provides individual units maximum flexibility to reach an emissions cap. It also encourages the development and installation of innovative control technologies. This is because a plant owner will be rewarded through the sale or banking of excess allowances if innovative technologies work, while at the same time the unit would not face the possibility of a shutdown if the technologies do not perform as expected, because managers could buy allowances or use banked allowances to achieve compliance.

### B. Cap-and-Trade Alternative Control Option

EPA has proposed a cap-and-trade program to regulate mercury emissions from coal-based power plants pursuant to its legal authority under §111 or §112(n)(1)(A) of the CAA. EEI agrees that EPA has legal authority to promulgate a cap-and-trade program under either §111 or §112. EEI believes, however, that EPA's proposal for a cap-and-trade program under §112(n)(1)(a) has practical advantages over a similar program promulgated under §111. We believe that a nationwide cap-and-trade program under §112 would create a more efficient regulatory structure than a similar program under §111(d), which could result in a patchwork system that may vary from one state to the next.

#### 1. Cap-and-trade under §112

As previously noted, §112(n)(1)(A) provides EPA with broad authority to craft regulations to address any public health concerns it identifies. Section 112(n)(1)(A) does not require EPA to regulate under §112(c) and (d). Instead, the provision provides generally that EPA shall regulate *under this section* if the Administrator finds that regulation is appropriate and necessary. EPA could establish regulations under §112(n)(1)(A) itself, or the MACT provisions of §112(d), or the risk-based provisions of §112(f) to meet the §112(n)(1)(A) command of regulating "under this section."

EEI believes the best reading of §112(n)(1)(A) is that Congress intended EPA to consider a variety of control options to address whatever heath concerns were identified in the Report to Congress[57] and then to promulgate rules based on the best of those options. Indeed, the limited legislative history of §112(n)(1)(A) supports a broad grant of authority. This legislative history indicates that EPA has broad discretion to establish regulatory standards, should it find such standards necessary to protect public health.

[57] "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress," EPA-453/R-98-004a, February 1998.

EEI believes that EPA's proposed cap-and-trade program pursuant to its legal authority under §112(n)(1)(A) is superior to the §111 program because §111 programs are implemented by the states, rather than the federal government, creating numerous procedural and administrative disadvantages. Passage of a cap-and-trade program under §111 will create a legal mechanism that requires each state to conduct rulemakings to implement the program. Each state will embark on a process involving numerous procedural hurdles and public participation (including any number of participants and special interest groups) that ultimately will be more difficult politically and more time consuming to implement than a federally mandated trading program. Such a program will lesson the effectiveness of a cap-and-trade program.

A program implemented under §112 will be a federal program, with one uniform national procedure. Federal cap-and-trade programs have proven successful in the past. For example, the Acid Rain Program, a national cap-and-trade program covering $SO_2$ emissions from utilities, has successfully resulted in a 41 percent reduction in $SO_2$ emissions from 1980 through 2002 (despite a significant increase in electrical generation). The $NO_x$ SIP Call rulemaking, a $NO_x$ emissions reduction program, also involves a cap-and-trade program that has resulted in a significant reduction of $NO_x$. And, as noted earlier, despite some claims that the Acid Rain Program and the $NO_x$ SIP Call rulemaking would result in "hot spots," there is no evidence that either has. It is clear that a cap-and-trade program can successfully reduce emissions without creating "hot spots."

Therefore, a federal cap-and-trade program will provide a more robust trading program with more certainty for the electric utility industry. For these reasons, EEI believes that a cap-and-trade program promulgated under §112 would provide more certainty and flexibility to industry, as well as provide the most certain level of reductions to mercury and nickel emissions.

### 2. Cap-and-trade under §111

If EPA decides to pursue cap-and-trade under §111, EEI believes that EPA's explanation of its legal authority to propose a cap-and-trade program under §111 of the CAA is reasonable.[58] The §111 program requires examination of two points: first, whether EPA has the authority under §111 to regulate HAPs that are listed under §112(b)(1); and second, whether a cap-and-trade program fits within the §111(a)(1) definition of a "standard of performance."

#### a. authority to regulate HAPs

Because nothing in the legislative history suggests that Congress sought to regulate HAPs exclusively under §112, §111 is a viable and appropriate statutory authority by which to regulate mercury emissions. Section 111(d) provides EPA with the authority to promulgate "standards of performance" that states must include in plans applicable to those sources.

EPA notes that two different and conflicting amendments to §111(d) were enacted in the 1990 Amendments to the CAA.[59] Where there are conflicting provisions in a statute, a federal agency must try to harmonize the conflicting provisions and adopt a reading that gives some effect to both provisions.[60] EPA harmonizes the differing language as follows: "Where a source category is being regulated under §112, a §111(d) standard of performance cannot be established to address any HAP listed under §112(b) that

[58] EPA states that it is establishing a subpart Da NSPS. It appears that EPA intends for its proposed rule to affect all facilities capable of firing over 25 MW. The subpart Da NSPS, however, only apply to Utility Units capable of firing more than 73 megawatts (MW) heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. *See* 40 C.F.R. §60.40a(a). Section 112 defines "electric utility steam generating unit" as "any fossil fuel fired combustion unit of more than 25 megawatts that serves as a generator that produces electricity for sale." *See* CAA §112(a)(8). An industrial cogeneration facility is defined under CAA §112 as a facility that "supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system. . . ." *See* CAA §112(a)(8). Accordingly, in its final rule, EPA will need to clarify that the rule covers facilities that sell more than 25 MW of electrical output whether or not they are covered by subpart Da NSPS.
[59] 69 Fed. Reg. at 4685.
[60] *See*, *e.g., Citizens to Save Spencer County v. EPA*, 600 F.2d 844 (D.C. Cir. 1979) (interpreting conflicting amendments under the CAA). In this case, due to the absence of any legislative history directly on point, EPA has focused on the plain language.

may be emitted from that particular source category."[61] The effect of this interpretation is that if EPA is regulating a source category under §112, §111(d) could not be used to regulate HAP emissions from that particular source category. As a result, in order to propose a cap-and-trade program under §111(d), EPA has proposed reversing its December 2000 regulatory finding to remove electric utility steam generating units from any regulation under §112. EEI believes that EPA's attempt to reconcile the differing language is reasonable and legally supportable.

**b. standard of performance**

A second issue involves whether a cap-and-trade system fits within the definition of "standard of performance" under §111(a)(1). "Standards of performance" are intended to reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."

EPA interprets the term "standard of performance," as applied to existing electric utility sources, to be a cap-and-trade program. The legislative history does not address whether an allowance or trading program was intended under the term "standard of performance." Congress's intent, however, was that existing sources be accorded flexibility in meeting regulatory standards, and thus, it is reasonable to interpret this legislative history as generally supporting a cap-and-trade program.[62]

Moreover, §111 "standards of performance" must reflect the degree of emission limitation achievable through application of "the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." CAA §111(a)(1). EPA proposes that a

[61] 69 Fed. Reg. at 4685.
[62] 69 Fed. Reg. at 4697.

cap-and-trade program has been adequately determined to be the best system for reducing mercury emissions from power plants.[63] After implementation of the control requirements by 2010 and 2018, EPA will evaluate the emission levels, health risks, and available control mechanisms to confirm whether the cap-and-trade program constitutes the "best system" of emissions reductions.

As stated above, EEI believes that EPA's explanation of its legal authority to propose a cap-and-trade program under §111 of the CAA is reasonable. EEI disagrees with EPA's proposal, however, to allow states to decide not to participate in a §111 trading program. Although states may have some authority under a §111 trading program, EPA cannot permit states to opt out of the §111 interstate trading program. Once EPA makes the determination, as it proposes to do here, that an interstate cap-and-trade program is the best system for reducing mercury emissions from coal-based power plants, states should not be allowed to interfere with that determination. Nothing in the Act or the legislative history gives states the ability to choose not to follow the guidelines established by EPA under §111.

If EPA permits states to opt out of a cap-and-trade program established under §111, this will lead to a patchwork approach that will affect the standard of performance that EPA has determined is the best system for achieving mercury emissions reductions from coal-based utility units. If EPA allows states to opt out of the trading program, this in essence permits states to change the standard of performance, which the CAA does not authorize.

EPA also cannot permit states not to issue all of the allowances available within the state. To allow a state to decide to participate in the trading program but not allocate all available allowances would effectively be to permit that state to modify the federally determined standard of performance, which the CAA does not allow. States do not have the authority under the CAA to change a standard of performance. Section 111(a)(1) makes clear it is EPA's obligation to set a standard of performance. Although a state

---

[63] Ibid.

does have authority under §111 to determine how to allocate mercury allowances to sources within its borders (such as by determining whether to have a permanent or an updated allocation), it must be required to allocate *all* of the allowances available to the state. Otherwise, it changes the standard of performance set by EPA.

In addition to having the authority to determine how to allocate allowances (provided all available allowances are issued), states can also be given the authority under §111 to "identify[] sources subject to the rule, issu[e] new or revised permits as appropriate, and determin[e] [mercury] allowance allocations," as EPA proposes.[64] Providing states with authority over these types of issues does not result in a change in the stringency of the standard of performance set by EPA. Any authority given to states, however, cannot fundamentally undermine the cap-and-trade program that EPA establishes under §111 because that program is the standard of performance that EPA has set, and states cannot change that standard.

If states choose to impose more stringent limitations under state law, sources within the state would presumably have extra §111 mercury allowances that they would no longer need to cover their mercury emissions as a result of the more stringent limitations. States must be prohibited from restricting the ability of sources to sell or trade any mercury allowances issued under the §111 trading program, including any allowances made available as a result of stricter state emissions limitations.

EEI believes that EPA's cap-and-trade proposal under §111 can be supported legally, but EPA must make it clear that states do not have the authority to decide not to participate in the interstate trading program or to participate but not to allocate all available allowances. EEI contends, however, that EPA's proposed rule under §112 is more legally defensible and provides a stronger basis upon which to promulgate a cap-and-trade program.

[64] 69 Fed. Reg. at 12413.

### 3. Design of a mercury cap-and-trade program

#### a. baseline for allowance allocation

EPA proposes to calculate the baseline heat input by using the average of the three highest heat inputs of the period 1998 to 2002.[65] Although this approach does have the benefit of avoiding the possibility that units will attempt to manipulate the baseline through actions such as fuel switching, it does present a problem in that the heat input data will be outdated by the time the trading programs begins. EEI suggests using the average of the three highest heat inputs of the period 1999 to 2003, which would be closer in time to when the actual trading program begins while preventing any manipulation of the data.

In addition, EPA must take steps to ensure that the heat input data for non-Title IV units are accurate. In its proposal, some of the heat input data that EPA provides for non-Title IV units are incorrect. It is important that the heat input data for these units be correct so that accurate baselines can be established.

#### b. permanent allocations with a set-aside for new sources

EEI supports a cap-and-trade program with permanent allocations of mercury allowances. Permanent allocations provide units with certainty regarding their allowances, which aids in planning. Permanent allocations also provide units with an incentive to improve energy efficiency and require fewer resources to administer as compared to an updated allocation system. This approach would provide the greatest amount of certainty to units and a less complicated method for allocating allowances.

New units may be impeded from entering service with a permanent allocation system. New units that begin service after the start of the trading program will still need to

[65] 69 Fed. Reg. at 4703. EPA would then adjust this baseline heat input using the revised adjustment factors discussed later in these comments.

comply with the cap-and-trade program by surrendering one allowance for each ounce of mercury emissions; however, under a strict permanent allocation system, new sources do not receive allowance allocations and would have to purchase or otherwise procure them. EEI suggests that the permanent allocation system be coupled with a set-aside of two percent of allowances for new sources. Any unused part of the set-aside should be returned to the other affected sources.

#### c. auctions

EEI opposes permitting states to decide whether to allocate allowances to sources within its borders for free or to hold an auction to sell them to the highest bidders. As noted earlier, states do not have the authority under §111 to make this decision because this would result in a fundamental change in the standard of performance set by EPA. States have authority to make decisions with regard to some elements of a §111 cap-and-trade program; however, states do not have authority under the CAA to make decisions that will result in a change in the stringency of EPA's standard of performance.

If EPA decides under a §112(n)(1)(A) cap-and-trade program to have allowance auctions, those auctions should not be for initial allocations of allowances, but should only be for a small amount of allowances each year as EPA does in the auction program in the Title IV Acid Rain Program. Any auction program for mercury should be patterned after the Title IV program and be similarly limited in scope. In addition, any proceeds from allowance auctions should not be deposited in the general revenues under the Miscellaneous Receipts Act but should instead be redistributed to compliance account holders on a proportional basis as occurs in the Title IV program.

#### d. banking of allowances without restriction

EEI supports EPA's proposal to allow banking of allowances without restriction after the start of the cap-and-trade program. Banking rewards sources for creating emission reductions beyond required levels by allowing the source to bank any unused allowances for later use. Banking encourages sources to reduce emissions earlier and in greater amounts. Although in theory banking may result in the future use of allowances to exceed the cap, this has not occurred in actual practice under the Title IV Acid Rain Program. In addition, EEI's proposal that the cap-and-trade program not begin until 2015 – addressed later in these comments – should minimize the concerns that some have expressed regarding banking.

#### e. early reduction credits

EEI supports providing a limited reserve of credits for early reduction credits at facilities that employ mercury-specific controls. This will provide companies an incentive to invest in innovative technologies and will stimulate the development of new mercury-specific controls – and/or complete retirement projects at coal-based units by 2014.

#### f. units emitting less than 25 pounds of mercury per year should be excluded

EEI supports EPA excluding those units which emit less than 25 pounds of mercury per year from the cap-and-trade program, provided that the overall cap for mercury emissions is not reduced by the small amounts that these sources emit (*i.e.,* the 2018 cap should remain 15 tons even if these sources are excluded from the program). EEI agrees with EPA that that mercury-specific control technologies under development will not practically apply to sources that emit less than 25 pounds of mercury per year.[66]

[66] 69 Fed. Reg. at 4699.

**g. all units should surrender the same numbers of allowances anywhere in the U.S.**

EPA should not require units in "sensitive" areas to surrender more allowances than units in other areas deemed less "sensitive" (*e.g.,* requiring some units to surrender two allowances for an ounce of mercury emissions than the standard one allowance). As noted earlier, a cap-and-trade program will not create "hot spots." Requiring different areas to surrender different numbers of allowances would greatly and unnecessarily complicate the trading program and result in an effective lowering of the cap.

**h. facility-wide compliance**

EEI supports EPA's proposal to require compliance on a facility-wide basis rather than on a unit-by-unit basis. This is what EPA did with the Title IV Acid Rain Program. Under this approach, instead of each individual unit having a unit account, each facility will have a "compliance" account, which will need to hold enough allowances to cover mercury emissions for the entire facility by the allowance transfer deadline.

**i. monitoring and compliance**

EEI is concerned with the monitoring method alternatives outlined in the supplemental notice. There are technical issues that need to be resolved before mercury CEMS can become allowance measurement devices. Mercury trading requires robust data; however, reporting hourly emission values for a pollutant whose bioaccumulation in the environment is only manifest over a period of years appears unwarranted. We believe that EPA's proposal is unfairly and unjustifiably biased against the dry sorbent method (Method 324). The option of allowing a facility to use either mercury CEMS or the dry sorbent method (Method 324) must be preserved.

EEI recognizes that there must be strict monitoring requirements for a trading program to be effective. We are concerned, however, with the quality assurance (QA) procedures proposed in the supplemental notice. In particular, under the sorbent trap monitoring option, the relative accuracy audit (RAA) procedures will be very costly and time-consuming, with each RAA taking up to a week to perform. We urge EPA to reduce the QA procedures for sorbent traps to the performing of one RATA per year.

### C. EEI Alternative to EPA Cap-and-Trade Option

#### 1. Phase 1 should be the true co-benefits level

EEI recognizes that the agency is attempting to provide the electric utility industry flexibility to achieve mercury reductions in a non-prescriptive and cost-effective manner in its cap-and-trade option. Nevertheless, the cap-and-trade program as proposed needs modification. EEI believes that a better cap-and-trade approach would involve three phases. In 2010, Phase 1 of the program would not specify a nationwide numeric mercury limit. Rather, the level of mercury emissions would be the level of reductions achieved by installing new control equipment to comply with the requirements of EPA's proposed CAIR rule – the true co-benefits level. The reason for not setting a numeric limit for Phase 1 is that there is no way to know what level of mercury emissions will be achieved as a result of utilities' efforts to meet the CAIR requirements. EPA recognized this problem when it requested comment on the level of mercury emissions that could be achieved in 2010 due to co-benefits.[67]

EPA,[68] EIA, EEI,[69] and UARG have all attempted to predict what control equipment electric utilities will install to meet the CAIR requirements and, correspondingly, what level of concurrent mercury emission reductions will occur. Each has produced a different prediction of the level of removing mercury emissions: EPA, 34 tons; EIA, 42 tons; EEI, 40 tons; and West Associates, 36.5 tons. As a practical matter, there is no way of knowing which prediction, if any, will actually occur.

---

[67] 69 Fed. Reg. at 4698 (Jan. 30, 2004).

[68] *See* Ibid.

[69] EEI and others contracted Charles River Associates to analyze the proposed mercury rule's options. A summary of this work and the model used is attached to these comments. See also footnote 63.

A second uncertainty involves whether all of the control equipment that needs to be installed to meet the CAIR requirements can physically be installed by the 2010 deadline. As EEI and UARG have noted in their respective CAIR comments, the 2010 CAIR caps cannot be completely achieved by that date. Those comments highlight the restrictions on manpower that will test many companies' ability to meet the CAIR requirements. If all of the control equipment that is projected for 2010 is not installed by that date, then the level of mercury co-benefits reductions due to FGD and SCR would be lower.

Companies treat their compliance plans as confidential business information, and those plans can change over time. Thus, one uncertainty in predicting the level of co-benefits in 2010 is what control equipment will actually be installed. Assuming that one could accurately predict the new control equipment that will be installed and schedule of the installation, there still is a third uncertainty about the level of mercury control that can be achieved by scrubbers and SCRs. As noted earlier, the degree to which SCRs convert elemental mercury to ionic mercury is an open question. To date, only limited testing has been conducted on SCRs and the results are contradictory. There also are questions about whether scrubbers remove all of the ionic mercury that enters them or whether some amount of ionic mercury reduces to elemental mercury. These and other questions make it impossible to predict the level of mercury control that will be achieved at a given unit equipped with a scrubber and/or an SCR.

For all the reasons noted above, estimating the level of mercury co-benefits that will occur in 2010 is, at best, a guess.[70] EEI believes true co-benefits ultimately will fall somewhere between 34 and 42 tons. EEI-sponsored modeling estimates co-benefits in 2010 to be about 40 tons.[71]

---

[70] Further, any changes in the final CAIR rule could affect the level of mercury co-benefits that are achieved.

[71] Attached to these comments is "Projected Mercury Emissions and Costs of EPA's Proposed Rules for Controlling Utility Sector Mercury Emissions," which describes the Electric Power Market Model (EPMM) and related data assumptions.

Because of this uncertainty, no matter what value EPA selects for the 2010 mercury co-benefits, there will be winners and losers. If the cap is set higher than the level of co-benefits that are actually achieved, then EPA will be criticized for creating a program that provides excess mercury allowances and that ultimately delays the date on which emissions are reduced to 15 tons because of banked allowances. On the other hand, if EPA sets the Phase 1 cap below the level of mercury co-benefits achieved by the installation of CAIR controls, then utilities will be required to add more control equipment to achieve additional mercury reductions.[72]

These results – where utilities have to install additional control technologies to meet a putative Phase I cap - are contrary to EPA's stated intent of having the first phase of the mercury cap-and-trade program reflect the co-benefits produced from meeting the CAIR requirements. These scenarios would produce economic inefficiencies and may adversely affect electric reliability in the U.S. To avoid these problems, the most straightforward approach is not to set a numeric limit for Phase 1. If no numeric cap is set, EEI agrees that mercury banking should not be allowed under Phase 1.

**2. Early mercury emissions monitoring**

EEI members would be willing to begin some form of mercury monitoring in 2008. Coal-based power plants will install and certify mercury CEMS or Method 324 sorbent trap monitoring systems before January 1, 2009. Continuous monitoring and reporting of mercury emissions will begin on January 1, 2009. This industry commitment to early mercury monitoring would provide EPA and the public with detailed information about the mercury emissions from each coal-based unit and would provide EPA and industry a gauge of the actual co-benefits that are achieved as CAIR-specific controls are installed in 2010.

---

[72] EPA is urged not to set a numeric level in 2010. If, however, the agency decides to do so in the final rule, EEI recommends a number greater than 34 tons. If actual emissions in the 2010-2014 years are higher than EPA's number, EEI agrees that industry should not benefit via bankable mercury credits. If, however, actual emissions are lower than EPA's number, EEI insists that industry be protected against unreasonable costs and the risk that mercury-specific controls are unavailable.

### 3. Mercury trading would begin in 2015

Phase 2 of the cap-and-trade program would begin in 2015. A nationwide mercury cap of 24 tons per year would apply. The mercury trading program would begin that year and mercury allowances would be made. Allowances would be based on heat input.

A large majority of EEI members support revised allocation adjustment factors of 1.0 (bituminous), 1.5 (subbituminous), and 3.0 (lignite). EEI supports this view, but also notes that there are a range of alternative views within the industry. Some Western companies support allocations of 1.0 (bituminous), 1.8 (subbituminous), and 3.6 (lignite). Companies that burn lignite support EPA's proposed multipliers (1.0 (bituminous), 1.25 (subbituminous), and 3.0 (lignite)).

In 2018, Phase 3 of the program would begin and the mercury cap would be reduced to 15 tons per year.

### 4. Advantages of alternative cap-and-trade program

EEI believes that this alternative cap-and-trade program has a number of advantages over the one proposed by EPA. First, it accurately addresses the level of co-benefits in 2010 by not setting a numeric cap. Secondly, it significantly reduces the amount of banking that can occur prior to 2018.[73] Thus, actual coal-based power plant emissions in 2018 are likely to be very close to or at 15 tons.[74] Finally, the alternative achieves greater mercury reductions sooner than EPA's proposal. Under EPA's proposal, EPA would distribute 34 tons of mercury allowances from 2010 to 2018 for a total of 272 tons of allowances.[75] By contrast, under the alternative proposal only 242 tons of mercury

---

[73] As stated earlier in this section, this alternative cap-and-trade program requires industry to forego banking until 2015. The cap-and trade option in the proposed rule, by contrast, allows banking to begin in 2010.
[74] Economic analysis of the proposed mercury rule's options performed for EEI indicates that the cap-and-trade option reduces emissions beyond co-benefits in 2010, and ultimately falls to 15 tons by 2020. Some banking of mercury is observed during Phase 1, but the bank is used up by 2020. See attached paper cited in note 62 for details.
[75] 34 tons/yr * 8 yr = 272 tons.

emissions would occur between 2010 and 2018.[76] Given these advantages, EPA should adopt the proposed alternative cap-and-trade program.

### D. MACT Alternative Control Option

#### 1. The recommendations of the "Industry Stakeholder Group" should be the basis of any MACT program

As noted earlier, EEI supports cap-and-trade as the preferred option for regulating electric power sector mercury emissions. Should EPA decide to promulgate a MACT standard in the final rule, however, EEI recommends that any MACT program follow the recommendations of the "Industry Stakeholder Group" of the Utility MACT Working Group which were presented to EPA on September 6, 2002. These recommendations are attached as appendix A.

#### 2. Subcategorization

EEI supports EPA's decision to divide the category of electric utility steam generating units into a number of subcategories. EPA's legal authority to create subcategories is clear in §112. Section 112(d)(1) provides EPA's discretion to distinguish "among classes, types, and sizes of sources within a category or subcategory in establishing standards." Section 112(c)(1) adds that "[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to section 7411 of this title and part C of this subchapter."

Under §111, EPA has previously subcategorized coal-based power plants based on the sulfur levels in the coals they burn.[77] This subcategorization approach was approved by

[76] Under the alternative proposal there would be no mercury allocations between 2010 and 2015. For purposes of this estimate, actual emissions are assumed to be 34 tons per year – EPA's current estimate of mercury co-benefits. Thus, emissions from 2010 to 2018 would be: (34 tons/yr * 5 yrs.) + (24 tons/yr * 3 yrs.) = 242 tons.

[77] *See* 40 C.F.R. Part 60, Subpart Da.

the D.C. Circuit in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). In approving EPA's NSPS regulations, the Court recognized that §111 allowed EPA "to distinguish among classes, types and sizes within categories."[78] The Court explained that "[o]n the basis of this language alone, it would seem presumptively reasonable for EPA to set different percentage reduction standards for utility plants that burn coal of varying sulfur content."[79] Thus, the Court found that EPA could create subcategories based on the type of fuel a unit burns.

EPA's Utility Report clearly demonstrates that the emissions from coal-based power plants are markedly different. These differences result from the amount and form of trace substances in each type of coal as well as the compounds that are created during the combustion process.

### 3. MACT floors

EEI is generally supportive of the MACT floors EPA has proposed for existing sources. EEI's primary concern with those limits is that EPA did not include the percentage reduction option supported by the "Industry Stakeholder Group" during EPA's Utility MACT Working Group meetings.

Any MACT floor should provide a unit the option of choosing between alternative standards based on either a stack limit or a percentage reduction. An alternative standard is needed to address the wide variations in mercury levels in coal. Providing an alternative standard avoids inequities based on the mercury content of coal burned and is consistent with EPA's stated desire of not favoring certain fuels over others.

With respect to the lignite limit, EPA must address the fact that the best performing units on which the MACT limit is based, all obtain their coal from one seam in North Dakota (Fort Union Lignite). By setting the limit at this proposed level, EPA will inadvertently be

---

[78] Ibid. at 318.
[79] Ibid.

setting a limit which is unachievable for units that use Gulf Coast lignite, the mercury content of which is at least double that of the Fort Union region. As such, EPA should set separate MACT floors for the two Lignite regions which demonstrate very different coal characteristics.

### 4. Beyond-the-floor analysis

EEI agrees with EPA's determination that available technologies or work practices do not provide a viable basis for establishing standards beyond the MACT floors.[80] In the preambles to the proposed rule and supplemental notice, EPA provides detailed discussions about the status of mercury control technologies and why it is premature to assume that 90 percent control of mercury emissions is currently achievable.[81] EEI concurs that 90 percent control of mercury emissions is not achievable with any currently available technologies.[82]

According to DOE, "Today, there is no commercially available technology that can consistently and cost-effectively capture mercury from coal-based power plants."[83] A technology needs to be installed in full-scale applications at a number of sites and operated over extended periods of time before it can be viewed as commercially available. Commercial availability requires that most of the key engineering questions about the technology have been previously resolved. A technology is not commercially available if one installs it knowing that many problems will need to be solved as experience is gained with the technology – that is the definition of a prototype unit, not a commercially available one.

---

[80] *See* 69 Fed. Reg. 4675.
[81] *See* 69 Fed. Reg. 4679-80; 69 Fed. Reg. 12,402-03.
[82] *See* J.E. Cichanowicz, "Hg Control Technology Commercial Availability for Beyond-the-Floor Application"; J.E. Cichanowicz, "The Role of Precombustion Hg Controls in Establishing the MACT Floor".
[83] Feeley et al., *A Review of DOE/NETL's Mercury Control Technology R&D Program for Coal-Fired Power Plants*, U.S. Department of Energy, National Energy Technology Laboratory, April 2003.

#### 5. Form of standard

As noted above, EEI believes that any MACT based limit should be in the form of an alternative standard that allows a unit the choice of complying with either a stack limit or a percentage reduction limit. An alternative standard is the best way to account for the differences in the mercury content in the various coal ranks and to ensure that certain coal seams are not favored over others.

In its MACT alternative, EPA has proposed a choice of either an input-based or an output-based stack limit for existing units. For new units, EPA has proposed only output-based limit. As several industry representatives noted during the EPA utility MACT working group meetings, output-based limits are unlikely to result in greater energy efficiency from coal-based units. Fuel costs are the major component in the cost of producing electricity. Thus, electric utilities already have great incentives to see that heat energy from combustion is efficiently converted into electricity. Imposing an output-based limit will not change the way in which electric utility steam generating units are operated.

Regardless, EEI supports EPA's proposal to allow existing units to comply with either an input-based or output-based limits.[84] EEI also concurs with EPA about providing only an output-based limit for new units.

#### 6. Compliance issues

EEI refers EPA to UARG comments on this issue for more detail, but offers several general comments.

---

[84] All of the data used to develop EPA's proposed MACT limits was input-based. Thus, to develop output-based limits, EPA had to employ efficiency conversion factors. The factors chosen by EPA – 32% for existing units and 35% for new units – are reasonable.
EPA has also requested comment on whether it should revisit these efficiency factors periodically. EEI does not believe that the efficiency factors should be revisited. Coal-based power plants are designed to maximize energy recovery. The basic design of coal-based boilers has changed little over the last several decades. Revisiting efficiency factors only creates regulatory complications with no commensurate benefit.

EEI supports the use of a long-term average to demonstrate compliance. We concur with EPA that "Hg is not an acute health hazard in the context of its emission from Utility Units." 69 FR 4668. We acknowledge that stack testing would not be cost-effective in obtaining a long-term average (except perhaps at low-emitting units, where variability and total mercury mass is not a significant concern for compliance). Therefore, EEI agrees with the conclusion that there is no need for continuous operating limits where a continuous measurement method such as mercury CEMS or Method 324 is used.

EEI also supports the development of an alternative monitoring scheme for low-emitting units. EPA should consider periodic fuel testing, periodic Method 324 analysis, and periodic stack testing as potential options depending upon the nature of the source's emissions.

### 7. Compliance time

EPA has proposed to require compliance with its MACT limits within three years of the effective date of those limits, which is consistent with the requirements of CAA §112(i)(3)(A). These requirements would be in addition to the requirements of the CAIR. EPA has not proposed to extend this compliance time as it has discretion to do under the CAA, but has requested comments on whether an extension is justified. As a practical matter, all electric utility steam generating units will not be able to comply with the proposed MACT limits within three years. Full compliance may require five years or more. EPA must make use of the compliance extensions provided in the CAA to provide an orderly retrofitting of mercury control equipment on coal fired power plants.

CAA §112(i)(3)(B) grants the EPA Administrator discretion to extend the deadline for existing sources by one year "if such additional period is necessary for the installation of controls." EPA has requested comment as to whether a one-year extension "should be granted for facilities required to install controls in order to comply with the section 112 MACT rule." 69 Fed. Reg. 4682. EEI supports EPA using its discretionary authority to extend the compliance deadline for all existing units.

CAA §112(i)(4) allows the President to exempt "any stationary source from compliance" for any number of two-year periods if doing so is in the national security interest of the United States and if the technology to implement the standard is not available. Both findings can be made regarding the implementation of EPA's proposed MACT rule.

Retrofitting units to comply with the mercury MACT – as well as the proposed CAIR – will require units to be taken off-line during the construction phase. Only so many plants taken can be off-line in a given region before the power grid in that region – and perhaps throughout the nation – is affected. According to the Energy Policy Report released by the Vice President's Energy Task Force, there is a currently a shortage of energy generation capacity in this country, causing an imbalance between supply and demand. This imbalance "will inevitably undermine … our national security."[85] This imbalance, or supply shortage, will only be exacerbated by taking multiple units off-line concurrently to install mercury control equipment. In light of the events of this past summer, it is in the national security interest to grant further extensions to some electric utility steam generating units.

Sufficient technology is not currently available on the scale needed to ensure a rapid and safe retrofit process in the time period established under the CAA. Mercury-specific controls necessary to comply with the rules as proposed are, at the very least, in a demonstration phase.[86]

EPA estimates that wide-scale availability of advanced control technology like ACI will not occur until 2015 – a full seven years after the proposed MACT compliance deadline.[87] Additionally, the "technology to implement the standard" includes the material necessary to install scrubbers and SCR units. Without the necessary materials and construction equipment, units cannot be retrofit with control technology, and the standard cannot be implemented. In short, there is a lack of available control technology to comply with the standard by EPA's proposed deadline. Thus, there are

---

[85] Report of the National Energy Policy Development Group, "National Energy Policy," (May 2001), at viii.
[86] *See* "Supplemental Notice to the Proposed Rule," 69 Fed. Reg. 12,398, 12,403 (March 16, 2004).
[87] Ibid.

reasonable grounds for at least a two-year presidential extension for many coal-based units, in addition to the one-year EPA extension EEI supports for all facilities.

### E. New Sources

As proposed, the mercury emission standards for new coal-based units are unduly stringent, will severely hinder the financing and construction of new coal-based power plants, will prevent the use of coal from many seams, and are inconsistent with the requirements of the CAA.[88]

EPA's proposed standards for new sources must be revised to fully account for variability in the performance of the "best performing" unit, regardless of whether it imposes a MACT limit or a cap-and-trade program.[89] The agency should add a "percent reduction" alternative for new units. Finally, if EPA chooses a cap-and-trade program, it must ensure that new facilities have reasonable access to mercury emission allowances.

If the mercury emission limit for new coal sources is set at the proposed emission rate, coals from many regions of the country will be unavailable for use in new coal plants, eliminating billions of tons of domestic, affordable coal from the nation's energy supply. This result is clearly contrary to EPA's stated goals. According to the proposed rule, "EPA feels that the intent of the CAA is to develop standards that, to the greatest extent reasonably possible, are consistent across the industry and avoid actions that create regional disparities."[90]

EEI agrees with EPA's statements supporting flexible fuel choices. Unfortunately, the agency's proposed new source MACT limit does not achieve that goal. Instead, EPA's

---

[88] *See* generally 69 Fed. Reg. 4652 (Jan. 30, 2004).
[89] These comments address both the MACT limit and the NSPS limit for new units, respectively. It is understood that the two limits for new units are equivalent.
[90] 69 Fed. Reg. at 4669.

limit would eliminate the possibility of using most coals, potentially eliminating coal as an option for new generation.

An emission limit developed pursuant to §112(d) of the CAA must reflect the maximum degree of reductions in emissions of HAP that is achievable taking into consideration the cost of achieving the emissions reductions, and energy requirements. For new sources, "the maximum degree of reduction in emissions that is deemed achievable for new sources in a category … shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source…."[91] 42 U.S.C. §7412(d)(3). EPA must identify the level of performance that the best performing unit can achieve virtually all the time.

EEI believes that EPA has not based its proposed MACT standard for new coal-based units on the level of performance that is "achievable" by a unit that is "similar" to most new coal-based units. It appears that EPA has simply combined all units as "similar" based on the type of fuel they use, without taking into account differences in process types, unit size, differences in coal constituents within a given fuel rank, differences in coal mercury content, and other variables.[92]

The Agency must establish that a unit on which the new source MACT is based is "similar" to most other conventional boilers within that coal rank, and that the rate is an actually achievable rate "under the most adverse conditions" reasonably expected to occur. By setting the new source limits at the proposed levels which are unjustifiably stringent, EPA will be inadvertently mandating the use of coal from specific seams or regions. This runs contrary to EPA's stated aversion to mandating the use of a specific fuel type.

---

[91] Note that while the limit established for new units must be based on "similar" units, the limit for existing units is based on "the average emission limitation achieved by the best performing 12 percent of the existing sources…." CAA § 112(d)(3)(A). Congress' decision to include the word "similar" in relation to new units is significant. EPA must consider differences among units when establishing an emission limit for new units. EPA should not have used the same approach for setting MACT limits for new and existing sources.

[92] 69 Fed. Reg. at 4667. *See* Docket A-92-55, Entry II-B-8. Memorandum from William Maxwell to the Utility MACT Project File, "Analysis of variability in determining MACT floor for coal-fired electric utility steam generating units."

Finally, no technology has been demonstrated that achieving the emission rate proposed under the MACT or NSPS regulatory schemes on a commercial scale for all but the lowest mercury content coals. No vendors of control technology are currently willing to guarantee mercury removal at the rates needed to achieve the proposed emission levels.

## X. COMMENTS ON NICKEL PROPOSAL

### A. EPA's Decision to Regulate is Inappropriate

EEI strongly believes that EPA has no jurisdiction to regulate nickel from oil-fired plants since specific health concerns associated with HAP emissions were not identified when EPA listed those units under §112(c).[93] An extensive literature exists which indicates that few compounds of nickel may be regarded as carcinogenic or potentially carcinogenic in humans.[94] Regulation of nickel based on the established toxicological and carcinogenic properties of specific nickel compounds (as EPA has done for mercury and chromium) would be a more appropriate approach than assuming equal cancer potency for all nickel species. Until EPA identifies and factually supports specific public health concerns associated with the emission of a given HAP, the agency does not have jurisdiction to regulate nickel emissions from oil-fired units.

EPA's limited database of 13 stack tests is inadequate to establish a MACT standard for a source category with 140+ units. The limits proposed in the rule appear to have been based on tests performed on only two oil-fired units. Section 112(d) of the CAA requires that the MACT floor be set with reference to the best-performing 12 percent of the sources for which EPA has emissions information. One can only conclude that EPA adopted this definition literally: since the agency has nickel emissions data for only 17

[93] *See* 65 Fed. Reg. 79,830 col. 2, Dec. 20, 2000.
[94] See comments submitted by Florida Power &Light Co. (FPL) in this docket. FPL and several other utilities have sponsored research to evaluate the speciation of Ni emissions from oil-based facilities. Specifically evaluated was the presence of nickel subsulfide ($Ni_3S_2$). The results of this research indicate that no $Ni_3S_2$ was found in the four units analyzed, which is contrary to EPA's assumption that 50 percent of the mercury emissions from oil-based units was the carcinogenic form – $Ni_3S_2$.

oil units, it used two units (*i.e.,* 12 percent of 17) to set the standard. EEI believes that EPA should have used at least the top five units for which it had emissions information to set the nickel standard.

EPA appears to recognize the more limited amount of information it has regarding nickel, both in terms of emissions and in terms of potential health effects, and has solicited current owners and operators of oil-fired units to provide additional information including current operating status, anticipated mode of operation in the future, current control technology, up-to-date information on fuel use, emissions, stack parameters and other location-specific data that would be relevant to the assessment of emissions, dispersion and ambient air quality. For affected source owners to research and provide meaningful data before the close of the comment period will be very difficult at best.

Nevertheless, the collection of additional data would be a better way for EPA to proceed in lieu of promulgating specific regulations for nickel. The existing database supports neither EPA's contention nor the requirement of achievability imposed by both §§112 and 111 of the CAA.

### B. Other Issues

#### 1. Format of the standard

Regarding the format of the proposed rule, EEI recommends that the standard be based on an annual calculation of nickel emissions. This would allow affected facilities to account for all fuel combustion if the standard is input-based, and all generation if it is output-based. This would also allow averaging across multiple affected units at a single facility.

### 2. Compliance

EPA has yet to define a compliance schedule for nickel under the alternative mercury cap-and-trade approach. With respect to the alternative (cap-and-trade) approach, we urge EPA to allow greater flexibility in achieving required limits through a trading or broader geographic averaging approach. In addition, we urge EPA to set any compliance deadline for nickel under the alternative scenario on a timeline parallel to the $SO_2$ and $NO_x$ reductions under the CAIR and the mercury reductions under the cap-and-trade program. Lastly, the proposed Clear Skies legislation allows compliance with the nickel limits to be demonstrated using a particulate matter surrogate. We request that EPA consider a similar alternative option in the current proposal.

### 3. Monitoring and testing deadlines

Under §63.9991(b), the Ni emission limit will apply "immediately" to any exempt oil-fired units (units that fire 98 percent distillate oil) that subsequently burns a fuel other than distillate fuel. The rules, however, do not include any deadlines for demonstration of compliance with that limit. Obviously, even with a planned change in fuel, it likely is not possible to begin performance testing the minute the new fuel is combusted. As a result, EPA should clarify when/how compliance for these units must be demonstrated and should provide a reasonable amount of time for performance testing once the new fuel is combusted.

### 4. Definitions

EPA states in the preamble that a unit is considered to be "oil-fired" if it fires oil "in amounts greater than or equal to 2 percent of its annual fuel consumption." The two percent value is intended to represent the amount that a gas-fired unit might use for start-up. Although the applicability provisions in §63.9982(a) exclude units combusting "natural gas at greater than or equal to 98 percent" of the unit's annual fuel consumption, this limitation on what units are considered "oil-fired" is not reflected in the definitions. The definition of "oil-fired" should be revised to reflect exclusion of oil consumption for "less than or equal to 2 percent" of fuel consumption." (The preamble statement is inconsistent with § 63.9982(a) in that it says that a unit that combusts exactly two percent oil would be oil-fired. Under §63.9982, that unit would not be affected.)

In the proposed definitions of "distillate oil" and "residual oil" in §63.10042, EPA has added a requirement related to the nitrogen content of the fuel. Nitrogen content is not a specification that is included in the cited ASTM definitions and is not a specification that is included in the definition used under Part 72 – which is for "diesel fuel." As a result, the definitions would appear to require testing to establish the nitrogen content. EPA has provided no rationale or justification for basing qualification of fuel as distillate or residual based on nitrogen content. Accordingly, EPA should remove that specification and adopt a definition of "distillate oil" that is consistent with the definition in Part 72 and that references appropriate ASTM specifications.

### 5. Certain units should be excluded

EEI agrees with EPA's decision to exclude units that burn oil less than two percent of the time from compliance with the nickel emission limits applicable to oil-fired units.[95] Examples of such units include peaking units, low-use units, and gas-fired units that use oil as a back-up fuel, and also coal units that use oil for start-up purposes. EPA should also exclude certain units that burn oil continuously, but that operate at very low capacity factors. Such units would also be considered peaking units. An exclusively oil-fired unit that has an annual capacity factor of two percent will generate nickel-from-oil emissions comparable to those of a gas (or coal) unit with a 90 percent capacity factor that burns oil two percent of the time (and that EPA proposes to exclude). Thus EPA should exclude from nickel regulation those oil fired units that have very low capacity factors.

[95] "EPA considers a unit to be an oil-fired unit if… it fires oil in amounts greater than or equal to two percent of its annual fuel consumption." 69 Fed. Reg. 4705.

In deciding what specific capacity factor level below which oil-fired units should be excluded, EEI encourages EPA to take of the precedent in its existing regulations. EPA's current regulations[96] define an oil-fired unit as a unit that burns more than 10 percent oil over three years and more than 15 percent in any single year of annual heat input; peaking units are defined as units with a capacity factor of less than 10 percent over three years and no greater that 20 percent in any single year. The emissions from such units clearly would be lower than even a very well-controlled unit that is burning oil at much higher capacity factors. Thus considering these existing EPA regulations, EPA should consistently also exclude from the definition of oil fired units any oil-only-fired unit with a capacity factor of less than 10 percent. If EPA does not agree with this 10 percent capacity factor exclusion level, EPA must include and specify some level of exclusion for oil-only units.

EPA should also clarify precisely how this exemption will be determined.[97] It should state that the applicability of the exemption is based on oil use as a percent of the unit's annual heat input. In addition to these comments on the nickel proposal, EEI also supports the more detailed comments of the Class of '85 Regulatory Response Group and the Clean Energy Group.

## XI. CONCLUSIONS

EEI believes that, despite dramatic decreases in emissions from the electric generating sector in recent decades, further cost-effective reductions in emissions may be achieved under the proper framework, especially under a properly designed national cap-and-trade program. Legislation provides greater certainty for business and the environment, while regulation generally fails to address the overlapping nature of more than a dozen existing interconnected air programs. Any new regulations must begin to

---

[96] *See* 40 C.F.R. Sec. 72.2.

[97] There are inconsistencies in the proposed rule. The preamble states that a unit is considered to be an oil-fired unit and subject to the nickel MACT if it is equipped to fire oil and/or natural gas, and if "it fires oil in amounts greater than or equal to two percent of its *annual fuel consumption*." 69 Fed. Reg. 4705. However, the same preamble states that the nickel MACT would not apply to units that combust natural gas "greater than 98 percent *of the time.*" Ibid. at 4657.

integrate and streamline these programs if the mercury rule is to achieve the desired emission reductions at reasonable cost to the American consumer. A cap-and-trade approach is the best way to reduce emissions from the electric utility industry. Such a rule would be protective of public health, scientifically sound, flexible, and cost-effective – all components of reasonable and sensible public policy.

## APPENDIX A: Recommendations of the "Industry Stakeholder Group"

### a. Subcategorization

EPA should establish subcategories for the source category of electric utility steam generating units. Fluidized bed combustion units should be in a separate category and Integrated Gas Combined Cycle (IGCC) units should be exempt. Conventional boilers must be subcategorized by coal rank (bituminous, subbituminous and lignite); other considerations could include process differences and coal chemistry for further subcategorization.

### b. MACT Floors

MACT floors for subcategories must account for the inherent variability in mercury emissions from the best performing units. There are numerous methods for addressing variability, and more than one approach may be necessary to account for variability related to fuel and variability related to plant operations.

### c. Beyond-the-Floor Regulation

There is currently no justification for regulation beyond the MACT floor.

### d. New Units

There should be no additional requirements beyond what is required to meet the MACT floor for existing units and to satisfy NSPS requirements.

### e. Format of Standard

There should be a choice between the least stringent of either a percent reduction standard (% mercury removed as difference between mercury in coal and mercury emitted from stack) or input-based emission rate (stack concentration in lb/TBTU) standard.

### f. Compliance Monitoring Method

Compliance should be monitored using EPA Method 101A, since mercury CEMs will most likely not be commercially available, accurate, or reliable by the time that a mercury MACT rule is to be implemented. Title V permits will include compliance assurance monitoring (CAM) plans for periods between compliance tests. There should be an initial compliance demonstration followed by annual testing for large sources and biennial testing for small sources to demonstrate compliance with mercury MACT limits.

### g. Compliance Unit

Compliance with MACT limits should be on a facility basis rather than on a boiler-by-boiler basis.

### h. Compliance Time

The presumptive three-year compliance period contained in § 112(d) is too short to bring <u>all</u> coal-based units into compliance with mercury MACT limits. Several practical concerns limit the ability to design, build and finance the pollution control equipment that would need to be installed or retrofitted for the entire electric utility industry to comply with a MACT standard in only three years.

### i. Oil-Fired Plants

EPA has no jurisdiction to regulate nickel from oil-fired plants since specific health concerns associated with HAP emissions were not identified when EPA listed those units under §112(c). EPA's database is inadequate to establish a MACT standard for this source category.

**PROJECTED MERCURY EMISSIONS AND COSTS OF EPA'S PROPOSED RULES FOR CONTROLLING UTILITY SECTOR MERCURY EMISSIONS**


**Anne E. Smith**
**Scott J. Bloomberg**
**John L. Rego**
**Charles River Associates**
**Washington, DC**

**John H. Wile**
**E&MC Group**
**Stony Brook, NY**


**June 10, 2004**

# I. PURPOSE OF THIS PAPER

This paper documents the methods, data, and output of the analysis Charles River Associates (CRA) used to analyze the two alternative policy proposals that EPA published in the *Federal Register* on January 30, 2004 for controlling utility Hg emissions. The emissions projections were developed using the Electric Power Market Model (EPMM), which is a tool for simulating future operational decisions and costs of the U.S. and Canadian electric power sector under various demand, price, technology, and policy conditions.

This paper contains the following sections:


Section II. Overview of the Analysis

Section III. Description of the Model Used

Section IV. Assumptions for Key Model Inputs

Section V. Details of Scenario Specifications

Section VI. Results of Scenarios

Section VII. Differences from EPA in Mercury Banking

## II. OVERVIEW OF THE ANALYSIS

The Electric Power Market Model (EPMM) is a linear programming model with intertemporal optimization or "foresight". EPMM simulates a competitive market for electric power and determines the mix of system operational choices that minimizes the present value of incremental costs in meeting electric demands in the 33 interconnected U.S. and Canadian electric markets, while also meeting other system requirements, including emissions caps or emissions rate limits. Incremental costs include (1) fixed and variable operating costs (including fuel costs and emissions allowance costs) for all units and (2) the capital costs for investments in new units and retrofits at existing facilities. This least-cost outcome is the outcome that would be expected to occur in competitive wholesale power markets. In the process of estimating and minimizing incremental costs, EPMM produces projections of control technology retrofits and emissions by unit. EPMM outputs also comprise regional competitive energy prices (by year, season and load period), regional capacity prices by year, and equilibrium allowance prices for capped emissions by year.

EPMM was originally developed by Dr. John Wile of E&MC Group for use in analyzing utility emissions policies related to sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$). In 2001, CRA and E&MC Group initiated a collaboration to enhance EPMM to be able to address multi-pollutant policies for the electric industry, including Hg and $CO_2$. Enhancements to EPMM that are especially relevant to the current analysis effort included adding logic and data to project mercury emissions from electricity generation, and to simulate a range of mercury control policies, including the unit-specific controls of a maximum achievable control technology (MACT) policy as well as Cap & Trade policies. Special effort has been given to developing and incorporating into the model a sound representation of:

- Hg content of available types of coals,
- Co-control of Hg by existing types of control equipment on power units,
- Costs and effectiveness of emerging technologies designed specifically to remove Hg from stack gases, and
- Relative shares of key chemical species in the portion of the Hg that is emitted from the stack, accounting for the specific set of controls and coal that a generating unit has in place.

Additionally, the model logic was enhanced to be able to simulate unit-by-unit emissions rate limits more precisely than the typical linear programming model. For each Hg control technology retrofit investment, EPMM identifies the operational level that will just satisfy each unit's unique emissions reduction need. This logic enhancement allows

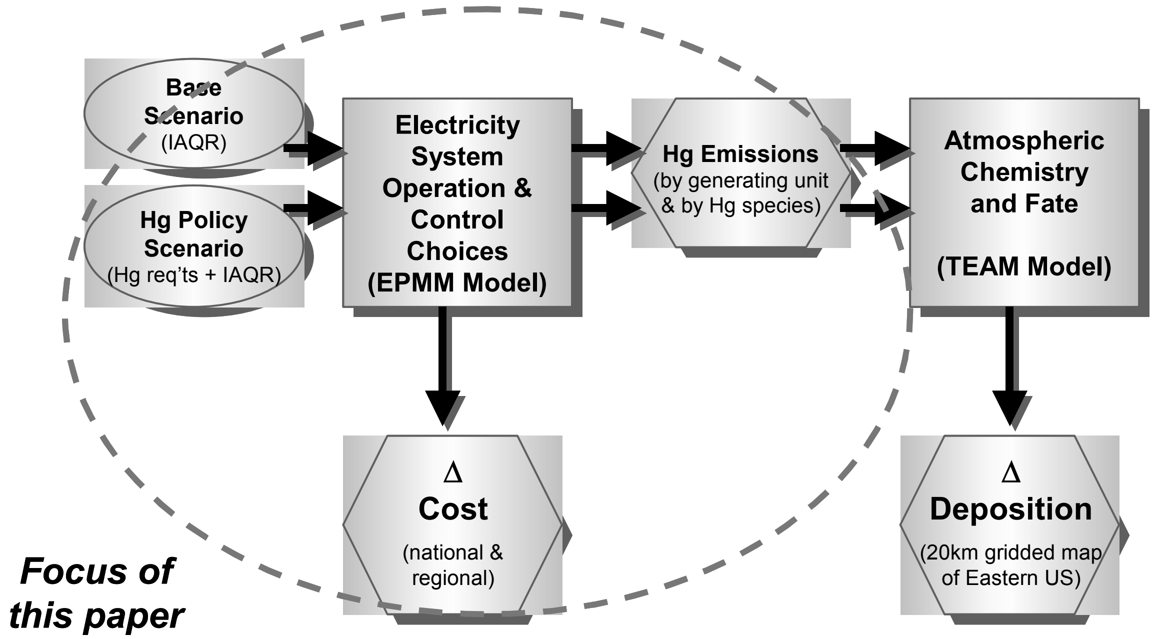
EPMM to avoid the excess control and excess costs that other similar models, such as EPA's IPM model, project when simulating unit-specific control requirements. Model logic was also added that would allow consideration of future technological improvement in the still-immature Hg control methods.

EPMM has been run using input data from standard government sources that are publicly available. For example, it relies on the U.S. Energy Information Administration (EIA) and Federal Energy Regulatory Commission (FERC) for data on the universe of U.S. generating units, and for prices of primary fuels used in generation. It uses North American Electricity Reliability Council (NERC) data for forecasted demand by region, and transmission capabilities among regions.

EPA is the primary source for data on emissions rates and for control technology cost and effectiveness. The one exception is for Hg control and emissions data. Hg control technology is developing at a rapid rate, and this analysis has used information provided by the Electric Power Research Institute (EPRI) and affiliated researchers for assumptions on costs and effectiveness of activated carbon injection (ACI). Assumptions regarding Hg co-benefits from existing control equipment were developed primarily from EPA's 1999 Information Collection Request (ICR) data. Industry researchers and EPA, however, have differing opinions on how to extrapolate ICR data to unit configurations that were not represented, or which were poorly represented in the ICR sample. Co-benefits assumptions used in this analysis reflect judgments of EPRI and other industry researchers on Hg control. This paper documents all of the above assumptions.

Figure I-1 illustrates the flow of information in this overall analysis process. The dotted line in Figure I-1 encircles the specific elements of the overall analysis process that are documented in this paper.

**Figure I-1. Diagram of Information Flows in EPRI Analysis of Hg Deposition Impacts of Alternative Policy Proposals**




The analysis focused on a comparison of the EPA Hg Cap & Trade proposal to its proposed MACT scenario. Both of those scenarios were modeled individually. However, because decisions on $SO_2$ and $NO_x$ controls can play an important role in determining Hg emissions, and the species of Hg emitted, the analysis also had to make specific assumptions about what $SO_2$ and $NO_x$ policies would also be in effect. Given EPA's stated preferences in the proposals, emissions limits like those in the proposed Interstate Air Quality Rule (IAQR) were assumed to be implemented simultaneously with the Hg proposals. Thus, each of the following scenarios was simulated with EPMM:

1. **Base Case** – includes existing national (Title IV, $NO_x$ SIP Call) and state regulations.
2. **IAQR Only** – includes provisions of the proposed IAQR, as well as existing national and state regulations.
3. **IAQR + Hg Cap & Trade** – includes provisions of the proposed IAQR and the proposed Cap & Trade provisions of the Hg Rule, as well as existing national and state regulations.
4. **IAQR + Hg MACT** - includes provision of the proposed IAQR and the alternative MACT provisions of the Hg Rule, as well as existing national and state regulations.

# III. DESCRIPTION OF THE MODEL USED

## *OVERVIEW OF THE ELECTRIC POWER MARKET MODEL*

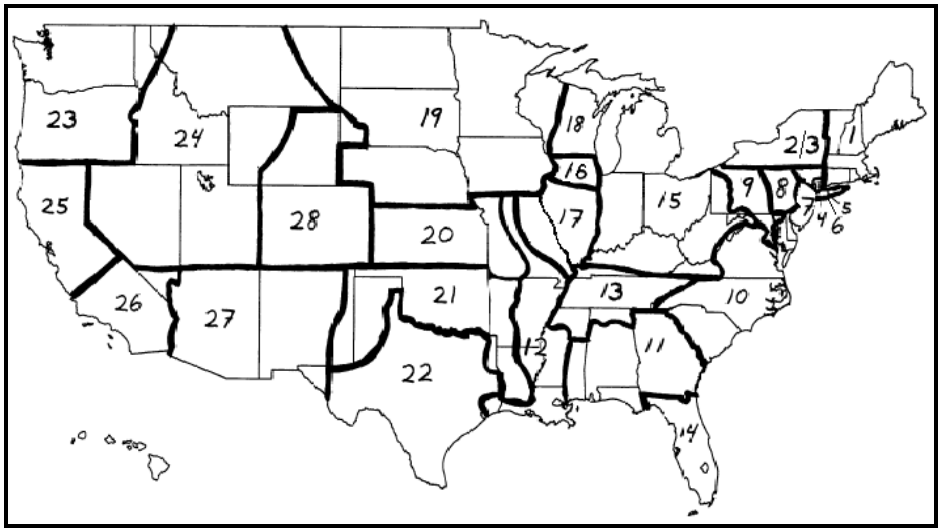
EPMM employs detailed unit-level information on the more than 10,000 generating units in the United States and Canada and simulates the implications of policy options on operational and generation construction decisions. There are 33 regions in EPMM based on NERC sub-regions.[1] The United States is divided into 28 regions (Figure III-1). There are also 5 regions reflecting Canadian markets, which are interconnected with the U.S. These geographical boundaries reflect regions in which electricity generation units are generally dispatched as a system, or power pool. Power can flow between these regions, but such flows are constrained by the available capacity of transmission lines that connect them. Thus, most determinants of power system investment and operation decisions tend to relate to demand and generating units specific to each region.

Environmental regulations, (whether unit-specific, regional, or national) also affect system decisions within each region. Both emissions rate limits and emissions caps (which effectively place an operational cost on each unit's emissions) can affect the mix and timing of new capacity additions as well as retrofits at existing facilities, fuel choice by all units, and dispatch of all units. EPMM captures all of these impacts in the process of optimizing unit responses to environmental policies. EPMM projects these decisions by accounting for incremental costs over a long time horizon. In the current analysis, specific investments and operational decisions associated with each policy scenario are simulated through 2020, while accounting for associated incremental system costs through 2040.

EPMM determines competitive energy prices by balancing supplies of and demands for electricity by year, season, and by time of day for each of the 33 electric markets (regions) while taking into account the potential for transmission of electricity from one region to another.

[1] For some NERC sub-regions where there were important internal transmission constraints, sub-regions were further divided.

**Figure III-1. Regional Detail in EPMM**
(Five Canadian regions not shown)




| | |
|---|---|
| 1. New England | 2. NYISO, West |
| 3. NYISO, Capital | 4. NYISO, Hudson Valley |
| 5. NYISO, New York City | 6. NYISO, Long Island |
| 7. PJM East | 8. PJM Central |
| 9. PJM West | 10. VACAR |
| 11. Southern | 12. Entergy |
| 13. TVA | 14. FRCC |
| 15. ECAR | 16. Com Ed |
| 17. South MAIN | 18. WIUM |
| 19. MAPP | 20. SPP North |
| 21. SPP South | 22. ERCOT |
| 23. Washington/Oregon | 24. Idaho, Utah, Montana |
| 25. Northern California | 26. Southern California/Nevada |
| 27. Arizona/New Mexico | 28. RMPP |

*Electricity demands* are represented with a set of load duration curves that reflect the peak demands, energy requirements, and hourly load variations specific to each region. For each region and year, there is a separate load duration curve for each of four seasons with each of these curves divided into five blocks, or load periods, having different average demands that reflect peak load, three levels of mid-level load, and a base load. The initial shapes of each region's load duration curves reflect historical hourly electricity demands of the region. Over the period of analysis, usually through 2020, the demand levels for each load period and each season change depending on projected demand growth. Also, the relative demands (the shape of the load duration curve) in each season change to the extent that peak demands and energy requirements grow at different rates leading to changes in load factors.

*Electricity supplies* include all existing utility and non-utility generating units, generating facilities under construction, and potential generic new additions as well as purchase power agreements. Supplies also include possible transmission from units in other regions, subject to explicit transmission limits among regions.[2] Generating units are dispatched in least-cost order to meet the demands reflected in the load duration curves in each region.[3] The unit costs that EPMM takes into account in setting the dispatch order include:

- Fuel costs, which are calculated given each unit's characteristics, including unit type, fuel type, fuel price, and heat rate.

- The unit's non-fuel variable operating cost, which includes costs of existing emissions control equipment.

- When an emissions cap is in effect, variable costs also include the emissions rate of the unit (given whatever control retrofit may have been adopted) multiplied by the current price of allowances.

- If an inflexible emissions limit is imposed on a unit (i.e., there is no emissions trading allowed), that unit must be able to meet its limit in order to remain on-line (even if it is not dispatched), and the variable cost of the associated emissions control action is also included in the dispatch cost.

- The cost of power imported from units in other regions includes losses during transmission.

In dispatching the units, EPMM also takes into account any limits on each unit's operation including forced outage rates, maintenance requirements, and equivalent availability factors.

The dispatch logic is combined with the level of demand in each load block to determine which units are dispatched. The dispatch cost of the last unit in the dispatch order is the energy price for that load period. This process provides projections of the energy prices that would emerge in a competitive power market because, under competition, output will be produced at lowest cost.

---

[2] When the difference in energy prices between interconnected markets exceeds the losses associated with transmitting power between the markets, the units will be re-dispatched in the two markets. Generation will increase in the region with the lower costs and decrease in the region with higher costs. This re-dispatch continues until (1) the difference in prices in the particular season and load period just equals losses from moving power between the markets or (2) the limit on power flows between the two regions is reached.

[3] Nondispatchable units are dispatched first to meet demands irrespective of their variable operating costs.

Unit dispatch decisions are just one of several actions that are taken in the model to meet demand at least cost. New capacity must also be built if demand grows to the point where regional capacity falls below required reserve margins. Also, environmental constraints must be met, and the model determines the least-cost way of doing this while accounting for how units will be dispatched and what new units will become part of the mix. The model uses linear programming logic to determine the simultaneous combination of all available system operation choices that minimizes the present value of the *incremental* costs over the period of the analysis across all of the interconnected markets.

In addition to projecting competitive regional energy and capacity prices, EPMM outputs include:

- The types, amounts, and timing of new capacity additions.
- Capacity factors of existing and new generating units.
- Prices of emissions allowances.
- Retrofits for complying with emissions constraints.
- Fuel use by type for existing and new generating facilities.
- Maintenance scheduling for existing and new units.
- Economic capacity and energy transactions among regions.

There are many inputs, or assumptions, underlying the projections produced by such a model. The following is a list of the most important input assumptions in EPMM. They are specified for each region. Specific assumptions for the key inputs in the list below are provided in Section IV:

- Existing utility and non-utility generating units, generating units currently under construction, and on-going modifications to existing facilities. Data required for each unit are:
  - Capacity
  - Unit type
  - Fuel type
  - Heat rate
  - Non-fuel O&M costs
  - Equivalent forced outage rate
  - Maintenance requirements
  - Emissions rates and limits, where applicable, for $SO_2$, $NO_x$, Hg, and $CO_2$

- Existing emissions control equipment for PM, $SO_2$, and $NO_x$
- Percentage removal rates of emissions for existing equipment configuration
- Unit-specific retrofit control equipment options for $SO_2$, $NO_x$, and Hg.

- New generation capacity options (in addition to units under construction) that the model can add. In addition to the existing unit characteristics listed above, new generating options require assumptions on their capital and variable operating costs.

- Retrofit control technologies available to reduce $SO_2$, $NO_x$, and Hg. Assumptions describing each option are capital cost, fixed and variable operating costs, and emissions removal efficiency.

- Peak demand and energy requirements.

- Hourly variations in electricity demand.

- Capacity reserve margin requirements.

- Projections of regional fuel prices.

- Transmission-related information:
  - Limits on capacity and energy transactions among regions in a market
  - Losses for interregional power flows
  - Wheeling charges for interregional transactions.

- Finance-related information:
  - Capital structure and cost of money
  - Income tax rates
  - Property tax and insurance rates
  - Book life for new generating options
  - Tax life for new generating options
  - Treatment of deferred taxes
  - Construction period for new generating options.

### *COMPARISON OF EPMM TO THE IPM MODEL USED IN EPA ANALYSES*

EPA uses the IPM model for its analysis of costs and emissions of proposed policies that impact the electricity sector. The IPM model is very similar methodologically to EPMM. Both are dynamic linear programming models of U.S. electricity markets. Both minimize a comparable measure of incremental system costs subject to a similar set of operational constraints. The primary difference between the two models is in the assumptions that are used in each model. Other minor differences exist in the choice of model disaggregation. Table III-1 compares the key assumptions of the two models. Section IV provides the specific quantitative values used for some of the key assumptions that differ from those of IPM.

## Table III-1. Comparison of EPMM and IPM[4]

| | | EPMM | IPM (*citations to IPM documentation in italics*) |
|---|---|---|---|
| **Model Detail and Structure** | Number of Regions | 33 (including 5 in Canada) | 26 (does not include Canada - specifies a level of net imports) *pp. 3-2, 3-7* |
| | Number of Modeled Unit Groups | Approximately 1,100 (nearly 600 coal unit-groups) | Approximately 1,400 (650 coal unit-groups) *p. 4-9* |
| | Reporting Years | 2004, 2008, 2010, 2012, 2015, 2018, 2020 | 2005, 2010, 2015, 2020, 2026 *p. 6-2* |
| | Model Terminal Effects | Terminates costs and benefits of new units over 20 years (2020-2040) | Terminates costs and benefits over 6 years (2026-2030) *p. 6-2* |
| | Fossil Unit Mothballing/ Retirements | Allows mothballing and economic retirements of fossil units. There are no fixed operating lives for fossil units. | Allows economic retirements for fossil units (mothballing not listed as option in documentation) *pp. 3-11, 6-2, 6-3* |
| | Nuclear Units | All nuclear units are assumed to receive life extensions, based on determination that these extensions are economic | All nuclear units are assumed to receive life extensions, based on determination that these extensions are economic *p. 3-11* |
| | Timing of Retrofits | Allows one retrofit decision per unit after any 2004 retrofit actions | Allows two retrofit decisions per unit over the time horizon *p. 6-2* |
| | New Unit Types | Conventional coal, IGCC, 2 types of CC and 2 types of GT; also range of renewables | Conventional coal, IGCC, CC, 2 types of GT, advanced nuclear; also range of renewables *pp. 4-9, 4-16* |
| | Repowering | Assumed to be uneconomic relative to building new capacity | Repowering allowed if economic (coal to CC or IGCC, oil/gas steam to CC) *p. 4-31* |
| **Key Data and Assumptions** | Mercury Control Costs | Variable O&M costs and effectiveness from EPRI; costs can improve over time | Cost and effectiveness based on update of NETL/EPA's ORD pilot study; ACI has higher cost per pound removed than EPMM *L1 p. L1-2* |
| | Mercury Control Options | ACI - % incremental removal based on needs of unit - from 0% to 90% (for bituminous/sub-bituminous); 0% to 75% (lignite) | ACI - either a 60% total removal or 90% total removal; 60% removal only in sensitivity runs *L1 p. L1-2* |
| | $NO_x$ and $SO_2$ Controls | Cost and percentage removals are EPA's assumptions for IPM | $NO_x$ costs and performance based on EPA's ORD and Bechtel Power Corporation; $SO_2$ costs and effectiveness based on EPA's ORD *pp. 5-4, 5-8* |
| | Coal Unit Availability | 80% | 85% *p. 3-8* |
| | Nuclear Capacity Factors | 85% for all units | 85% to 90% as a national average *p. 4-29* |
| | Fixed O&M | Fixed over life of unit | Variable depending on unit age *p. 4-10* |
| | Life Extension Costs | Not included | $5/kW-Yr for fossil units after 30 years (based on AEO 2003) *Table of Updates, p. 3* |
| | Electricity Demand Growth | Based on detailed forecasts from NERC, approximately 1.7% per year | Based on AEO 2003, with modifications for Climate Change Action Plan (CCAP), approximately 1.1% per year *B, p. B-* |
| | Coal and Gas Prices | Gas prices based on AEO 2004; coal prices based on FERC 423 but with AEO efficiency improvements over time | Gas prices based on ICF Consulting's North American Natural Gas System, with prices much lower than AEO 2004; coal prices based on AEO 2003 coal supply curves *Table of Updates, pp. 6-7* |

[4] *Documentation of EPA Modeling Applications (v.2.1)*, March 2002 and *Documentation Supplement for EPA Modeling Applications (V.2.1.6),* July 2003 at http://www.epa.gov/airmarkets/epa-ipm.

*LIMITATIONS OF MODEL RESULTS*

All models are an idealization of the real world and there are limitations in how one can interpret their results. These limitations apply to both EPMM and IPM alike:

- The models present an idealized response to policies that reflects perfect foresight of market outcomes up to 25 or 35 years into the future. Real world choices may differ from the model results because of expectations different from those in the model forecasts, or because of risk aversion.

- The models do not reflect or capture many real-world constraints, such as resource limitations, that may be associated with many utilities simultaneously attempting to retrofit a large portion of their capacity.

- The models probably overstate the ease of compliance in the near-term as neither one estimates or applies upper bounds on rates of retrofitting, and neither accounts for the possible difficulties imposed by the immature state of Hg control technology.

Model results from both EPMM and IPM should therefore be interpreted with caution. At best, they should be viewed as estimates of how much control action would be desired to meet emissions targets in a "perfect" world, with no uncertainty and no resource limitations. Model projections of control measures should not be automatically accepted as feasible or realistic.

# IV. ASSUMPTIONS FOR KEY MODEL INPUTS

***UNIT DATA AND AGGREGATION***

Generating units in EPMM are often aggregated together to form "unit-groups." Most large units are individually represented, and it is primarily the smaller units that are grouped together. As a result, there are over 500 coal unit-groups in the current version of EPMM, compared to about 1100 individual coal-fired units. The unit-groups consist of units within the same region that have similar characteristics and would thus be dispatched and retrofitted similarly. Characteristics that determine unit grouping include: regional location, unit capacity, prime mover, pollution control equipment, heat rate, fuel choice, sulfur content of current coal burned and operating costs.

There are 305 GW of coal-fired generating capacity among the existing units in the EPMM data base. Of this, 83 GW already have either wet or dry scrubbers. Also, there are 87 GW of SCR or SNCR among the existing units. When retrofits are reported for EPMM scenarios, those numbers are incremental to these existing control technology installations.

***DEMAND***

The fundamental driver of generation in each region is demand. Table IV-1 provides each region's annual total demand for each of the modeled years, and Table IV-2 provides each region's peak demand. These inputs are obtained from the NERC's Electricity Supply & Demand (ES&D) forecasts.

The demands in Tables IV-1 and IV-2 are configured into the load duration curves that determine when generating units are dispatched. There is a different load curve for each of four "seasons" and the load curve in each season is represented by five load blocks, each with a different average demand level. The five load blocks comprise peak load, three levels of mid-level load, and base load. There are different numbers of hours in each of these five load levels, and the number of hours varies by the season. The hours in each block were selected to provide a good approximation of each season's unique load duration curve shape. Table IV-3 shows how the five load periods were defined for each season.[5]

[5] The total hours in each row of Table IV-1 equals the total hours in the months that comprise each row's "season". The sum of all the hours in the table is 8760, which is the number of hours in a year.

**Table IV-1. Annual Energy Demand**
(thousands of MWh)

| Sub-Region | 2004 | 2008 | 2010 | 2012 | 2015 | 2018 | 2020 |
|---|---|---|---|---|---|---|---|
| NEPP | 130,286 | 138,099 | 142,242 | 147,426 | 154,833 | 162,612 | 168,013 |
| NYISO, West | 54,112 | 55,881 | 56,791 | 57,694 | 59,153 | 60,721 | 61,803 |
| NYISO, Capital | 11,750 | 12,134 | 12,331 | 12,528 | 12,844 | 13,185 | 13,420 |
| NYISO, Hudson Valley | 21,909 | 22,625 | 22,994 | 23,359 | 23,950 | 24,585 | 25,023 |
| NYISO, New York City | 53,294 | 56,512 | 58,163 | 59,811 | 62,282 | 64,755 | 66,401 |
| NYISO, Long Island | 21,596 | 22,867 | 23,481 | 24,358 | 25,522 | 26,805 | 27,743 |
| PJM Eastern | 154,318 | 163,038 | 167,196 | 171,478 | 178,157 | 185,095 | 189,871 |
| PJM Central | 43,949 | 46,825 | 48,243 | 49,704 | 51,982 | 54,364 | 56,012 |
| PJM Western | 83,670 | 89,548 | 92,166 | 94,799 | 98,945 | 103,273 | 106,263 |
| VACAR | 309,733 | 338,054 | 351,316 | 365,014 | 386,636 | 409,539 | 425,556 |
| SOU | 244,670 | 268,672 | 281,790 | 295,641 | 317,630 | 341,254 | 357,972 |
| Entergy | 142,628 | 148,704 | 154,304 | 160,174 | 169,353 | 179,059 | 185,836 |
| TVA | 172,610 | 186,495 | 192,701 | 196,094 | 203,616 | 211,427 | 216,800 |
| FRCC | 220,249 | 245,426 | 256,880 | 268,265 | 286,778 | 306,568 | 320,515 |
| ECAR | 584,897 | 621,737 | 640,910 | 660,539 | 691,221 | 723,329 | 745,558 |
| Com Ed | 100,950 | 106,700 | 109,650 | 112,607 | 117,250 | 122,085 | 125,419 |
| South MAIN | 106,001 | 112,872 | 116,383 | 120,066 | 125,760 | 131,721 | 135,850 |
| WIUM | 69,355 | 73,851 | 76,148 | 78,558 | 82,283 | 86,183 | 88,885 |
| MAPP | 157,110 | 167,768 | 172,696 | 177,824 | 185,760 | 194,050 | 199,781 |
| SPP North | 65,741 | 72,347 | 75,739 | 79,333 | 85,013 | 91,098 | 95,396 |
| SPP South | 139,709 | 149,693 | 157,262 | 162,412 | 172,655 | 183,544 | 191,182 |
| ERCOT | 313,603 | 349,675 | 369,733 | 390,941 | 425,056 | 462,148 | 488,657 |
| WA, OR | 134,015 | 141,437 | 146,057 | 150,677 | 158,002 | 165,682 | 171,009 |
| ID,UT,MT | 97,847 | 103,265 | 106,638 | 110,012 | 115,359 | 120,967 | 124,856 |
| N California | 129,280 | 134,325 | 136,831 | 139,286 | 143,126 | 147,073 | 149,764 |
| S California/Nevada | 140,053 | 145,519 | 148,234 | 150,893 | 155,054 | 159,329 | 162,244 |
| Arizona/New Mexico | 123,034 | 138,004 | 144,834 | 151,832 | 163,104 | 175,214 | 183,782 |
| RMPP | 58,116 | 63,718 | 66,775 | 70,028 | 75,167 | 80,683 | 84,583 |

## Table IV-2. Peak Energy Demand
(MW)

| Sub-Region | 2004 | 2008 | 2010 | 2012 | 2015 | 2018 | 2020 |
|---|---|---|---|---|---|---|---|
| NEPP | 25,066 | 26,442 | 27,210 | 28,137 | 29,478 | 30,884 | 31,858 |
| NYISO, West | 9,691 | 10,069 | 10,245 | 10,422 | 10,712 | 11,016 | 11,223 |
| NYISO, Capital | 2,104 | 2,186 | 2,225 | 2,263 | 2,326 | 2,392 | 2,437 |
| NYISO, Hudson Valley | 3,924 | 4,077 | 4,148 | 4,220 | 4,337 | 4,460 | 4,544 |
| NYISO, New York City | 11,196 | 11,702 | 11,922 | 12,142 | 12,472 | 12,802 | 13,022 |
| NYISO, Long Island | 4,926 | 5,236 | 5,400 | 5,603 | 5,913 | 6,251 | 6,465 |
| PJM Eastern | 32,463 | 34,558 | 35,597 | 36,626 | 38,263 | 39,973 | 41,156 |
| PJM Central | 6,935 | 7,311 | 7,493 | 7,678 | 7,960 | 8,254 | 8,455 |
| PJM Western | 15,136 | 16,372 | 16,972 | 17,630 | 18,644 | 19,717 | 20,466 |
| VACAR | 58,201 | 62,864 | 65,427 | 67,977 | 72,083 | 76,437 | 79,484 |
| SOU | 48,765 | 54,244 | 57,117 | 60,161 | 65,019 | 70,269 | 74,003 |
| Entergy | 26,172 | 27,696 | 28,786 | 29,889 | 31,647 | 33,508 | 34,810 |
| TVA | 28,257 | 30,941 | 31,835 | 32,712 | 34,107 | 35,560 | 36,564 |
| FRCC | 41,596 | 45,620 | 47,757 | 49,993 | 53,546 | 57,351 | 60,037 |
| ECAR | 101,436 | 109,609 | 112,738 | 116,622 | 122,175 | 127,993 | 132,024 |
| Com Ed | 22,750 | 24,700 | 25,700 | 26,720 | 28,343 | 30,064 | 31,269 |
| South MAIN | 19,669 | 20,936 | 21,669 | 22,482 | 23,715 | 25,016 | 25,923 |
| WIUM | 12,869 | 13,698 | 14,178 | 14,710 | 15,517 | 16,368 | 16,961 |
| MAPP | 28,355 | 30,834 | 31,842 | 32,862 | 34,470 | 36,157 | 37,328 |
| SPP North | 14,389 | 15,763 | 16,498 | 17,251 | 18,458 | 19,749 | 20,660 |
| SPP South | 27,585 | 29,735 | 31,156 | 32,100 | 33,997 | 36,006 | 37,411 |
| ERCOT | 63,028 | 70,314 | 74,638 | 79,228 | 86,648 | 94,763 | 100,591 |
| WA, OR | 23,660 | 24,759 | 25,555 | 26,396 | 27,693 | 29,055 | 30,000 |
| ID,UT,MT | 17,274 | 18,077 | 18,658 | 19,271 | 20,219 | 21,213 | 21,902 |
| N California | 24,883 | 26,492 | 27,330 | 28,182 | 29,520 | 30,922 | 31,894 |
| S California/Nevada | 26,957 | 28,699 | 29,607 | 30,531 | 31,981 | 33,499 | 34,552 |
| Arizona/New Mexico | 25,759 | 29,023 | 30,563 | 32,131 | 34,678 | 37,428 | 39,381 |
| RMPP | 9,836 | 10,840 | 11,410 | 11,956 | 12,869 | 13,850 | 14,546 |

**Table IV-3. Number of Hours in Each Seasonal Load Period**

| Months/Load Period | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| Jun, Jul, Aug | 50 | 139 | 476 | 676 | 867 |
| Dec, Jan, Feb | 29 | 409 | 925 | 655 | 142 |
| May, Sept. | 12 | 85 | 420 | 593 | 354 |
| Mar, Apr, Oct, Nov | 24 | 170 | 841 | 1,186 | 707 |

The electricity demand level associated with each of these blocks is tailored to reflect each region's own pattern of variability in load levels. For each model region, the average load observed in each block of hours is estimated as a percentage of the season's peak load for that region. These percentages indicate the load shapes within each region. Table IV-4 shows the initial load shapes for each of the U.S. model regions. These load shapes were based on recent historical demand patterns reported to the NERC.

The model adjusts the initial load shapes over time to reflect each region's forecasted growth in the peak loads and energy demands of Tables IV-1 and IV-2. The future load shapes mirror the initial load shapes if peak load and energy demand grow proportionally. If energy demand grows at a more rapid rate than peak load in a region, then the incremental demand is allocated to the four non-peak load blocks in such a way that the load curve is proportionately flattened for that region relative to its initial shape.

### Table IV-4. Energy Demand in Each Load Period as Percent of Peak Hour Load

| Region | Months | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|
| NEPP | Jun, Jul, Aug | 96.7 | 89.5 | 79.2 | 67.7 | 50.6 |
| NEPP | Dec, Jan, Feb | 88.9 | 80.2 | 70 | 54.9 | 46 |
| NEPP | May, Sept. | 90.9 | 78.6 | 68.9 | 55.8 | 41.9 |
| NEPP | Mar, Apr, Oct, Nov | 82.4 | 76.3 | 69.6 | 58.3 | 44.4 |
| NYISO, West | Jun, Jul, Aug | 95.8 | 91.3 | 84.9 | 74.9 | 61.7 |
| NYISO, West | Dec, Jan, Feb | 97.3 | 90.3 | 80.7 | 67.6 | 59.4 |
| NYISO, West | May, Sept. | 90.8 | 85 | 78.5 | 65.7 | 54.7 |
| NYISO, West | Mar, Apr, Oct, Nov | 91.5 | 86.6 | 80.4 | 69.7 | 58.1 |
| NYISO, Capital | Jun, Jul, Aug | 95.9 | 89.4 | 78.2 | 65.8 | 49.3 |
| NYISO, Capital | Dec, Jan, Feb | 79.2 | 71.2 | 62.4 | 50.3 | 42.9 |
| NYISO, Capital | May, Sept. | 89.6 | 77.3 | 64.1 | 52.8 | 40.2 |
| NYISO, Capital | Mar, Apr, Oct, Nov | 74.6 | 68.9 | 62.7 | 53.5 | 41.9 |
| NYISO, Hudson Valley | Jun, Jul, Aug | 95.9 | 89.4 | 78.2 | 65.8 | 49.3 |
| NYISO, Hudson Valley | Dec, Jan, Feb | 79.2 | 71.2 | 62.4 | 50.3 | 42.9 |
| NYISO, Hudson Valley | May, Sept. | 89.6 | 77.3 | 64.1 | 52.8 | 40.2 |
| NYISO, Hudson Valley | Mar, Apr, Oct, Nov | 74.6 | 68.9 | 62.7 | 53.5 | 41.9 |
| NYISO, NYC | Jun, Jul, Aug | 95.2 | 87.2 | 75.1 | 61.9 | 45.7 |
| NYISO, NYC | Dec, Jan, Feb | 69.6 | 62.3 | 53 | 39.3 | 32.6 |
| NYISO, NYC | May, Sept. | 92.8 | 75.8 | 60.5 | 47.5 | 34 |
| NYISO, NYC | Mar, Apr, Oct, Nov | 68.9 | 63.4 | 56.6 | 45.4 | 33.1 |
| NYISO, Long Island | Jun, Jul, Aug | 94.2 | 85.2 | 72.6 | 60.2 | 42.8 |
| NYISO, Long Island | Dec, Jan, Feb | 73.1 | 63.3 | 53.2 | 40.5 | 33.2 |
| NYISO, Long Island | May, Sept. | 90.2 | 70.6 | 56.1 | 45 | 31.8 |
| NYISO, Long Island | Mar, Apr, Oct, Nov | 68 | 61.1 | 53.7 | 44.6 | 32.5 |
| PJM Eastern | Jun, Jul, Aug | 95.3 | 87.7 | 76.9 | 65.5 | 49.9 |
| PJM Eastern | Dec, Jan, Feb | 80.5 | 71.8 | 62.7 | 51.5 | 43.5 |
| PJM Eastern | May, Sept. | 91.3 | 74.8 | 62.3 | 51.2 | 39.6 |
| PJM Eastern | Mar, Apr, Oct, Nov | 74.1 | 67.9 | 61.3 | 52.3 | 41.6 |
| PJM Central | Jun, Jul, Aug | 89.3 | 82.7 | 74.3 | 64.7 | 49.4 |
| PJM Central | Dec, Jan, Feb | 95.4 | 85.3 | 74.4 | 61.6 | 50.8 |
| PJM Central | May, Sept. | 82.3 | 73 | 65.8 | 54.3 | 42.2 |
| PJM Central | Mar, Apr, Oct, Nov | 86.1 | 79.3 | 70.3 | 60 | 47 |
| PJM Western | Jun, Jul, Aug | 96 | 88.8 | 78.2 | 65.8 | 49.8 |
| PJM Western | Dec, Jan, Feb | 86.3 | 74.3 | 63.8 | 53 | 43.7 |
| PJM Western | May, Sept. | 91 | 75.4 | 61 | 50.5 | 38.7 |
| PJM Western | Mar, Apr, Oct, Nov | 76.7 | 68.7 | 60.3 | 51.9 | 40.8 |
| VACAR | Jun, Jul, Aug | 95.3 | 89.3 | 80.7 | 68.7 | 52.9 |
| VACAR | Dec, Jan, Feb | 87.5 | 74.2 | 63.4 | 53.8 | 44.4 |
| VACAR | May, Sept. | 89.6 | 79.2 | 65.8 | 54.3 | 42.7 |
| VACAR | Mar, Apr, Oct, Nov | 78 | 69.3 | 60.5 | 53.2 | 43.2 |
| SOU | Jun, Jul, Aug | 97.2 | 92.5 | 84.6 | 71.3 | 54 |
| SOU | Dec, Jan, Feb | 79.8 | 66.6 | 56.9 | 47.9 | 39.7 |
| SOU | May, Sept. | 91.9 | 84.1 | 71.3 | 56.6 | 43.7 |
| SOU | Mar, Apr, Oct, Nov | 75.6 | 66.1 | 58.2 | 50.6 | 40.9 |
| Entergy | Jun, Jul, Aug | 97.3 | 93.3 | 86.6 | 75.5 | 60.4 |
| Entergy | Dec, Jan, Feb | 79.3 | 67.4 | 59.2 | 51.8 | 45.4 |
| Entergy | May, Sept. | 92.9 | 85.4 | 74.6 | 61.4 | 50 |
| Entergy | Mar, Apr, Oct, Nov | 78 | 69 | 61 | 54.4 | 46.3 |
| TVA | Jun, Jul, Aug | 94.1 | 86.6 | 68.1 | 73.1 | 64.7 |
| TVA | Dec, Jan, Feb | 91.5 | 77.8 | 66.7 | 57.3 | 48.1 |
| TVA | May, Sept. | 89.5 | 82 | 69.4 | 57.8 | 46.7 |
| TVA | Mar, Apr, Oct, Nov | 81.4 | 72.6 | 63.9 | 56.8 | 47.2 |
| FRCC | Jun, Jul, Aug | 96.4 | 91.2 | 82.8 | 69.5 | 50.2 |
| FRCC | Dec, Jan, Feb | 81.7 | 63.1 | 52.5 | 40.7 | 31.7 |
| FRCC | May, Sept. | 92.7 | 86.7 | 76 | 58.9 | 42.6 |
| FRCC | Mar, Apr, Oct, Nov | 84.8 | 75.6 | 62.9 | 49.5 | 36.2 |

| Region | Months | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|
| ECAR | Jun, Jul, Aug | 96.2 | 89.5 | 80.8 | 70.4 | 56 |
| ECAR | Dec, Jan, Feb | 87.3 | 78.7 | 70.5 | 59.8 | 51.8 |
| ECAR | May, Sept. | 86.6 | 78.9 | 69.3 | 59.2 | 48.6 |
| ECAR | Mar, Apr, Oct, Nov | 79.8 | 75.4 | 69.5 | 60.9 | 50.9 |
| Com Ed | Jun, Jul, Aug | 94.6 | 85 | 72.6 | 60.3 | 46 |
| Com Ed | Dec, Jan, Feb | 72.1 | 65.2 | 57.5 | 46.8 | 40.8 |
| Com Ed | May, Sept. | 83.4 | 70.2 | 58.7 | 48 | 38 |
| Com Ed | Mar, Apr, Oct, Nov | 67.4 | 62.5 | 57.9 | 48.6 | 39.5 |
| South MAIN | Jun, Jul, Aug | 96.7 | 89.5 | 78.8 | 65.9 | 52.2 |
| South MAIN | Dec, Jan, Feb | 78.6 | 70 | 62.4 | 53.3 | 46.5 |
| South MAIN | May, Sept. | 83.8 | 72.9 | 61.1 | 52.5 | 43.7 |
| South MAIN | Mar, Apr, Oct, Nov | 73.1 | 67.3 | 62 | 54.2 | 45.7 |
| WIUM | Jun, Jul, Aug | 95.9 | 90 | 81.7 | 72 | 57.1 |
| WIUM | Dec, Jan, Feb | 86 | 79.1 | 70.5 | 57.7 | 49.1 |
| WIUM | May, Sept. | 88.6 | 81.1 | 73 | 61.4 | 49.1 |
| WIUM | Mar, Apr, Oct, Nov | 83.9 | 78.4 | 72.7 | 61.8 | 50.2 |
| MAPP | Jun, Jul, Aug | 95.7 | 88.7 | 79.3 | 68.6 | 53.6 |
| MAPP | Dec, Jan, Feb | 86.2 | 79.1 | 69.5 | 58.5 | 50.9 |
| MAPP | May, Sept. | 87.2 | 76.1 | 66.9 | 56.3 | 45.3 |
| MAPP | Mar, Apr, Oct, Nov | 80.5 | 75.6 | 69.2 | 59.4 | 48.8 |
| SPP North | Jun, Jul, Aug | 96.6 | 90.3 | 80 | 65.3 | 48.8 |
| SPP North | Dec, Jan, Feb | 68 | 60.7 | 53.6 | 44.9 | 39.1 |
| SPP North | May, Sept. | 89.2 | 78.1 | 61.1 | 49 | 38.4 |
| SPP North | Mar, Apr, Oct, Nov | 66.7 | 59.8 | 54.5 | 47.2 | 38.6 |
| SPP South | Jun, Jul, Aug | 96.8 | 91.8 | 83.4 | 70.3 | 54.7 |
| SPP South | Dec, Jan, Feb | 70.2 | 60.9 | 53.6 | 45.7 | 37.4 |
| SPP South | May, Sept. | 90.7 | 80.5 | 65.5 | 53.1 | 42.8 |
| SPP South | Mar, Apr, Oct, Nov | 68.9 | 61 | 55.2 | 49.3 | 41.5 |
| ERCOT | Jun, Jul, Aug | 96.8 | 92.3 | 84.8 | 72.5 | 56.4 |
| ERCOT | Dec, Jan, Feb | 75.8 | 61.9 | 52.9 | 45.1 | 38.2 |
| ERCOT | May, Sept. | 92.3 | 85 | 71.8 | 57.2 | 44.6 |
| ERCOT | Mar, Apr, Oct, Nov | 77.3 | 65.8 | 55.8 | 48.5 | 39.6 |
| WA, OR | Jun, Jul, Aug | 76.6 | 73.5 | 69.4 | 63.6 | 52.6 |
| WA, OR | Dec, Jan, Feb | 95.7 | 84.6 | 74.6 | 63.3 | 54.6 |
| WA, OR | May, Sept. | 73.6 | 70.6 | 66.3 | 58.8 | 48.6 |
| WA, OR | Mar, Apr, Oct, Nov | 87.6 | 79.4 | 71 | 62.4 | 52.2 |
| ID,UT,MT | Jun, Jul, Aug | 96.7 | 93 | 86.9 | 77.9 | 63.8 |
| ID,UT,MT | Dec, Jan, Feb | 94.4 | 85.2 | 75.6 | 65.4 | 56.6 |
| ID,UT,MT | May, Sept. | 88.8 | 83.8 | 76.2 | 66.3 | 55.1 |
| ID,UT,MT | Mar, Apr, Oct, Nov | 87.6 | 80.4 | 73.5 | 65.6 | 55.3 |
| Northern California | Jun, Jul, Aug | 94.2 | 86.6 | 76.6 | 64.6 | 48.5 |
| Northern California | Dec, Jan, Feb | 74 | 65.9 | 57.1 | 44.8 | 37.9 |
| Northern California | May, Sept. | 89.1 | 79.1 | 66.8 | 54.2 | 41.6 |
| Northern California | Mar, Apr, Oct, Nov | 73.6 | 67.3 | 61.4 | 51.5 | 39.8 |
| S California and Nevada | Jun, Jul, Aug | 94.4 | 85.8 | 75.3 | 62.5 | 46.5 |
| S California and Nevada | Dec, Jan, Feb | 71.3 | 63.7 | 54.7 | 42.6 | 37.1 |
| S California and Nevada | May, Sept. | 95.9 | 84 | 68.2 | 53.6 | 41.1 |
| S California and Nevada | Mar, Apr, Oct, Nov | 78.4 | 69.8 | 61.7 | 50.2 | 39.4 |
| Arizona/New Mexico | Jun, Jul, Aug | 96.6 | 91.8 | 84.5 | 72.6 | 54.7 |
| Arizona/New Mexico | Dec, Jan, Feb | 69.8 | 61.4 | 53.7 | 45.8 | 39.2 |
| Arizona/New Mexico | May, Sept. | 92.7 | 85 | 72.5 | 57.1 | 43.3 |
| Arizona/New Mexico | Mar, Apr, Oct, Nov | 78.5 | 65.8 | 56.4 | 49.2 | 39.3 |
| RMPP | Jun, Jul, Aug | 96.8 | 91.9 | 84.3 | 74.5 | 59.8 |
| RMPP | Dec, Jan, Feb | 90.3 | 82.4 | 74.1 | 61.5 | 53.1 |
| RMPP | May, Sept. | 89.9 | 83 | 74.2 | 64.1 | 51.9 |
| RMPP | Mar, Apr, Oct, Nov | 85.3 | 79.4 | 73.6 | 65.4 | 53.5 |

*FUEL PRICES – NATURAL GAS*

Natural gas prices are based on Henry Hub wellhead prices from the Reference Case in *AEO 2004,* but gas futures prices are applied for the period 2004-2007. These are provided in Table IV-5. Delivery costs are added to these basic gas price assumptions to obtain the regional delivered prices that are used to determine unit fuel costs in each region. Table IV-6 shows the delivered gas prices that are input to the model.

**Table IV-5. Henry Hub Wellhead Gas Price Assumptions**
(1999$/MMBtu)

| Year | $/MMBtu |
|---|---|
| 2004 | $4.98 |
| 2008 | $3.56 |
| 2010 | $3.33 |
| 2012 | $3.65 |
| 2015 | $4.06 |
| 2018 | $4.03 |
| 2020 | $4.13 |

*FUEL PRICES – COAL*

Coal prices are based on delivered spot price data reported to FERC. Current assumptions are based on the 1999 price data. The reported delivered spot price data were divided into the price of each coal type delivered within its supply region and the incremental cost of that type of coal delivered to each of the other regions in the model. The price between a supply region and an electric market in the same general location is treated as comparable to an FOB price (although it should be noted that this price includes local delivery costs and is thus not formally an FOB price). The other destinations (not in the same general location) include a transportation adder. Table IV-7 shows the within-region prices for each coal type from each coal-producing region. Table IV-8 presents the transport costs to the different demand regions in the model. If there is no entry in the coal transport cost table, then it is not possible in EPMM for coals to be shipped between that origin-destination pair.

## Table IV-6. Delivered Natural Gas Prices
(1999$/MMBtu)

| Sub-Region | 2004 | 2008 | 2010 | 2012 | 2015 | 2018 | 2020 |
|---|---|---|---|---|---|---|---|
| NEPP | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| NYISO, West | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| NYISO, Capital | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| NYISO, Hudson Valley | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| NYISO, New York City | $5.44 | $4.00 | $3.76 | $4.07 | $4.45 | $4.41 | $4.49 |
| NYISO, Long Island | $5.44 | $4.00 | $3.76 | $4.07 | $4.45 | $4.41 | $4.49 |
| PJM Eastern | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| PJM Central | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| PJM Western | $5.35 | $3.92 | $3.68 | $3.99 | $4.37 | $4.34 | $4.42 |
| VACAR | $5.26 | $3.83 | $3.59 | $3.91 | $4.30 | $4.26 | $4.35 |
| SOU | $5.26 | $3.83 | $3.59 | $3.91 | $4.30 | $4.26 | $4.35 |
| Entergy | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |
| TVA | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |
| FRCC | $5.26 | $3.83 | $3.59 | $3.91 | $4.30 | $4.26 | $4.35 |
| ECAR | $5.17 | $3.74 | $3.51 | $3.82 | $4.22 | $4.19 | $4.28 |
| Com Ed | $5.17 | $3.74 | $3.51 | $3.82 | $4.22 | $4.19 | $4.28 |
| South MAIN | $5.03 | $3.61 | $3.38 | $3.70 | $4.10 | $4.07 | $4.17 |
| WIUM | $5.17 | $3.74 | $3.51 | $3.82 | $4.22 | $4.19 | $4.28 |
| MAPP | $5.03 | $3.61 | $3.38 | $3.70 | $4.10 | $4.07 | $4.17 |
| SPP North | $5.03 | $3.61 | $3.38 | $3.70 | $4.10 | $4.07 | $4.17 |
| SPP South | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |
| ERCOT | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |
| WA, OR | $4.89 | $3.48 | $3.25 | $3.58 | $3.98 | $3.96 | $4.06 |
| ID,UT,MT | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |
| N California | $5.21 | $3.79 | $3.55 | $3.86 | $4.26 | $4.22 | $4.31 |
| S California/Nevada | $5.77 | $4.31 | $4.06 | $4.36 | $4.73 | $4.68 | $4.75 |
| Arizona/New Mexico | $5.21 | $3.79 | $3.55 | $3.86 | $4.26 | $4.22 | $4.31 |
| RMPP | $5.12 | $3.70 | $3.46 | $3.78 | $4.18 | $4.15 | $4.24 |

**Table IV-7. Coal Prices Delivered to Model Region Containing Coal Source**
(1999$/MMBtu)

| ***Supply Region*:** | **AL** | **IL** | **IN** | **KS** | **KY** | **LA** | **MD** | **MT** | **ND** | **NM** | **OH** | **PA** | **TN** | **TX** | **VA** | **WV** | **WY** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Coal Type*** | | | | | | | | | | | | | | | | | |
| Bit, Low, Low | 1.41 | | 1.20 | | 1.37 | | | | | | | | | | 1.47 | 1.28 | |
| Bit, Low, Med | | | | | | | | | | | | 1.35 | | | | | |
| Bit, Med, Low | 1.36 | 1.37 | 1.15 | | 1.28 | | | | | | | | 1.49 | | 1.34 | 1.26 | |
| Bit, Med, Med | | | | | | | | | | | | 1.27 | | | | | |
| Bit, High, Low | | 1.17 | 1.01 | 1.04 | 1.24 | | | | | | | | | | | | |
| Bit, High, Med | | | | | | | 1.17 | | | | | | | | 1.34 | 1.12 | |
| Bit, High, High | 1.34 | | | | | | | | | | 1.02 | 1.15 | | | | | |
| Sub, Low, Low | | | | | | | | 1.23 | | 1.16 | | | | | | | 1.01 |
| Sub, Low, Med | | | | | | | | 1.25 | | 1.12 | | | | | | | 1.31 |
| Lignite | | | | | | 1.36 | | | 0.73 | | | | | 1.01 | | | |

### *COAL SWITCHING LIMITATIONS*

Certain types of coal switching are limited. No units may switch into or out of lignite coals in the EPMM runs. Further, EPMM limits the degree to which units currently burning bituminous coal can switch to subbituminous coals. Specifically, the Btu input of subbituminous coal at a unit designed to burn bituminous coal could not exceed 50 percent.[6]

Finally, there is a limit on the amount of each type of coal that is available. The availability of each type of coal is allowed to grow over the period of analysis by 2 percent per year. This assumption was based on historically observed rates, combined with the judgments of coal industry experts. The maximum quantity of each coal available in each modeled year is provided in Table IV-9.

[6] Blending of less than 50 percent subbituminous coal has been achievable in practice without substantial capital investments or upgrades, whereas higher percentages typically entail either costly derates or significant additional capital investments. As the model logic is unable to simulate these higher costs, EPMM simulations have not allowed the model to consider switching to subbituminous coal at these higher blend levels.

**Table IV-8. Coal Transportation Costs**
**(1999$/MMBtu)**

| ***Supply Region:*** | **AL** | **IL** | **IN** | **KS** | **KY** | **LA** | **MD** | **MT** | **ND** | **NM** | **OH** | **PA** | **TN** | **TX** | **VA** | **WV** | **WY** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Delivery Area*** | | | | | | | | | | | | | | | | | |
| NEPP | | | | | 0.65 | | | | | | 0.56 | 0.50 | | | 0.24 | 0.63 | |
| NYISO, West | | | | | | | | | | | | 0.27 | | | | 0.21 | |
| NYISO, Capital | | | | | 0.68 | | | | | | | 0.27 | | | | 0.21 | |
| NYISO, Hudson Valley | | | | | | | | | | | | | | | | 0.53 | |
| NYISO, Long Island | | | | | 0.32 | | | | | | 0.54 | | | | | | |
| PJM Eastern | | | | | 0.32 | | | | | | 0.54 | 0.11 | | | 0.24 | 0.24 | |
| PJM Central | | | | | 0.32 | | | | | | 0.54 | 0.11 | | | 0.24 | 0.24 | |
| PJM Western | | | | | 0.21 | | 0.00 | | | | | 0.11 | | | 0.24 | 0.24 | |
| VACAR | 0.00 | 0.36 | | | 0.29 | | | | | | | 0.23 | 0.34 | | 0.05 | 0.17 | |
| SOU | | | | | | | | | | | | | | | 0.26 | 0.27 | 0.80 |
| Entergy | | 0.00 | | | 0.04 | | | | | | | | | | | | 0.70 |
| TVA | | | | | 0.43 | | | | | | | | 0.00 | | 0.06 | 0.00 | |
| FRCC | | 0.05 | 0.00 | | 0.00 | | | 0.00 | | | 0.00 | | | | 0.40 | 0.31 | |
| ECAR | | 0.48 | | | | | | | | | | 0.00 | | | 0.00 | 0.00 | 0.47 |
| Com Ed | | 0.13 | 0.26 | | | | | | | | | | | | | | 0.54 |
| South MAIN | | 0.60 | 0.37 | | 0.56 | | | | | | | | | | | | 0.41 |
| WIUM | | 0.26 | 0.48 | | 0.34 | | | 0.08 | | | | 0.42 | | | | 0.29 | 0.38 |
| MAPP | | 0.85 | | 0.00 | | | | 0.10 | 0.00 | | 0.38 | 0.52 | | | | 0.49 | 0.25 |
| SPP North | | | | | | | | | | | | | | | | | 0.14 |
| SPP South | | | | | | | | | | | | | | 0.17 | | | 0.70 |
| ERCOT | | | | 0.41 | | 0.00 | | | | | | | | | | | |
| WA, OR | | | | 0.41 | | | | | | | | | | 0.00 | | | 0.48 |
| ID,UT,MT | | | | 0.41 | | | | 0.07 | | | | | | | | | 0.51 |
| S California/Nevada | | | | 0.41 | | | | | | | | | | | | | |
| Arizona/New Mexico | | | | 0.41 | | | | | | | | | | | | | 0.10 |
| RMPP | | | | 0.41 | | | | 0.07 | | 0.00 | | | | | | | 0.65 |

**Table IV-9. Maximum Coal Consumption by Coal Type**
(Trillions of Btus)

| Coal Type | Bituminous | | | | | | | Subbituminous | | Lignite | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Sulfur Content | Low | | Med | | High | | | Low | Med | | |
| Hg Content | Low | Med | Low | Med | Low | Med | High | Low | | | |
| **2004** | 3,366 | 10 | 4,416 | 533 | 1,962 | 1,103 | 1,661 | 7,360 | 1,138 | 1,229 | 22,776 |
| **2008** | 3,644 | 10 | 4,780 | 577 | 2,123 | 1,194 | 1,798 | 7,966 | 1,232 | 1,330 | 24,653 |
| **2010** | 3,791 | 11 | 4,973 | 600 | 2,209 | 1,242 | 1,870 | 8,288 | 1,282 | 1,384 | 25,649 |
| **2012** | 3,944 | 11 | 5,174 | 624 | 2,298 | 1,292 | 1,946 | 8,623 | 1,333 | 1,439 | 26,686 |
| **2015** | 4,186 | 12 | 5,490 | 663 | 2,439 | 1,371 | 2,065 | 9,151 | 1,415 | 1,528 | 28,319 |
| **2018** | 4,442 | 13 | 5,826 | 703 | 2,588 | 1,455 | 2,191 | 9,711 | 1,502 | 1,621 | 30,052 |
| **2020** | 4,621 | 13 | 6,062 | 732 | 2,693 | 1,514 | 2,280 | 10,103 | 1,562 | 1,687 | 31,267 |

### *TRANSMISSION LIMITS*

To ensure a realistic dispatch of units it is necessary to reflect constraints imposed by the transmission grid. Table IV-10 shows the maximum transmission flow among the 28 regions for the summer period.

## Table IV-10. Maximum Transmission Flow for Summer Months
(MW)

| From: / To: | NEPP | NYISO, West | NYISO, Capital | NYISO, Hudson Valley | NYISO, NYC | NYISO, Long Island | PJM Eastern | PJM Central | PJM Western | VACAR | SOU | Entergy | TVA | FRCC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEPP | | 150 | 500 | 500 | | 500 | | | | | | | | |
| NYISO, West | 150 | | 3,350 | 1,600 | | | 1,000 | | 1,000 | | | | | |
| NYISO, Capital | 800 | 1,999 | | 3,270 | | | | | | | | | | |
| NYISO, Hudson Valley | 800 | 1,600 | 1,999 | | 3,700 | 1,200 | 2,000 | | | | | | | |
| NYISO, NYC | | | | 1,999 | | 270 | 1,000 | | | | | | | |
| NYISO, Long Island | 500 | | | 1,200 | 420 | | | | | | | | | |
| PJM Eastern | | 1,000 | | 500 | 1,000 | | | 6,600 | | | | | | |
| PJM Central | | | | | | | 6,600 | | 4,700 | | | | | |
| PJM Western | | 2,075 | | | | | | 4,700 | | 3,440 | | | | |
| VACAR | | | | | | | | | 4,560 | | 3,477 | | 2,986 | |
| SOU | | | | | | | | | | 623 | | 2,749 | 2,776 | 3,600 |
| Entergy | | | | | | | | | | | 750 | | 700 | |
| TVA | | | | | | | | | | 2,986 | 3,224 | 3,177 | | |
| FRCC | | | | | | | | | | | 2,600 | | | |
| ECAR | | | | | | | | | 2,773 | 2,522 | | | 679 | |
| Com Ed | | | | | | | | | | | | | | |
| South MAIN | | | | | | | | | | | | 2,825 | 3,972 | |
| WIUM | | | | | | | | | | | | | | |
| MAPP | | | | | | | | | | | | 2,020 | | |
| SPP North | | | | | | | | | | | | 1,379 | | |
| SPP South | | | | | | | | | | | | 1,379 | | |
| ERCOT | | | | | | | | | | | | | | |
| WA, OR | | | | | | | | | | | | | | |
| ID,UT,MT | | | | | | | | | | | | | | |
| N California | | | | | | | | | | | | | | |
| S California/ Nevada | | | | | | | | | | | | | | |
| Arizona/New Mexico | | | | | | | | | | | | | | |
| RMPP | | | | | | | | | | | | | | |

### Table IV-10 (continued). Maximum Transmission Flow for Summer Months

| From: / To: | ECAR | Com Ed | South MAIN | WIUM | MAPP | SPP North | SPP South | ERCOT | WA, OR | ID,UT,MT | N Calif | S Calif/ Nevada | Arizona/ New Mexico | RMPP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEPP | | | | | | | | | | | | | | |
| NYISO, West | | | | | | | | | | | | | | |
| NYISO, Capital | | | | | | | | | | | | | | |
| NYISO, Hudson Valley | | | | | | | | | | | | | | |
| NYISO, NYC | | | | | | | | | | | | | | |
| NYISO, Long Island | | | | | | | | | | | | | | |
| PJM Eastern | | | | | | | | | | | | | | |
| PJM Central | | | | | | | | | | | | | | |
| PJM Western | 4,077 | | | | | | | | | | | | | |
| VACAR | 3,528 | | | | | | | | | | | | | |
| SOU | | | | | | | | | | | | | | |
| Entergy | | | 860 | | 750 | 200 | 200 | | | | | | | |
| TVA | 1,621 | | 2,028 | | | | | | | | | | | |
| FRCC | | | | | | | | | | | | | | |
| ECAR | | 4,000 | 2,000 | | | | | | | | | | | |
| Com Ed | 4,000 | | 3,700 | 1,100 | | | | | | | | | | |
| South MAIN | | 2,300 | | | 300 | 1,178 | | | | | | | | |
| WIUM | | 2,000 | | | 750 | | | | | | | | | |
| MAPP | | | 1,862 | 950 | | 2,077 | | | | 200 | | | | 310 |
| SPP North | | | 2,622 | | 523 | | 1,200 | | | | | | | |
| SPP South | | | | | | 1,500 | | 800 | | | | | 420 | |
| ERCOT | | | | | | | 800 | | | | | | | |
| WA, OR | | | | | | | | | | 2,250 | 4,360 | 3,100 | | |
| ID,UT,MT | | | | | 150 | | | | 3,750 | | 120 | 1,937 | 1,045 | 1,350 |
| N California | | | | | | | | | 3,675 | 100 | | 3,000 | | |
| S California/ Nevada | | | | | | | | | 3,100 | 1,417 | 2,400 | | 9,578 | |
| Arizona/New Mexico | | | | | | | 420 | | | 1,115 | | 10,118 | | 650 |
| RMPP | | | | | 310 | | | | | 3,400 | | | 550 | |

## *RESERVE MARGINS*

Capacity build is motivated by the need to serve growing loads. Table IV-11 provides the reserve margin requirements assumed for each region.

**Table IV-11. Percentage Reserve Margin Requirement**

| Sub-Region | Percent Margin |
|---|---|
| NEPP | 18 |
| NYISO, West | 18 |
| NYISO, Capital | 18 |
| NYISO, Hudson Valley | 18 |
| NYISO, New York City | 18 |
| NYISO, Long Island | 18 |
| PJM Eastern | 17 |
| PJM Central | 17 |
| PJM Western | 17 |
| VACAR | 16 |
| SOU | 16 |
| Entergy | 16 |
| TVA | 16 |
| FRCC | 20 |
| ECAR | 16 |
| Com Ed | 15 |
| South MAIN | 15 |
| WIUM | 15 |
| MAPP | 15 |
| SPP North | 13.6 |
| SPP South | 13.6 |
| ERCOT | 11 |
| WA, OR | 11 |
| ID,UT,MT | 11 |
| N California | 15 |
| S California/Nevada | 15 |
| Arizona/New Mexico | 13 |
| RMPP | 15 |

*CONTROL TECHNOLOGIES*

In modeling the scenarios described above, coal units were provided with retrofit options to meet $SO_2$, $NO_x$, and Hg restrictions. Wet FGDs are available as a retrofit to meet tighter $SO_2$ caps, SCRs are available for reducing $NO_x$ emissions (SCRs are also available to steam oil/gas units);[7] and ACI were available to lower Hg emissions.[8] The costs and characteristics for each retrofit option are included in Table IV-12. The percentage removals for Hg are *incremental* to the Hg removals that occur due to co-benefits. (Total Hg removal may therefore exceed 90 percent.)

The cost and effectiveness of ACI control technology is by far the most uncertain. Assumptions used in EPMM were developed by EPRI control technology researchers, based on experience with a very limited number of pilot and test installations. In these model runs, ACIs were only available in combination with a COHPAC unit, unless the unit has a fabric filter (FF) already installed.[9] This assumption was made because off-line calculations indicated that the ACI+COHPAC combination would almost always have a lower cost per pound of Hg removed than the ACI alone. Thus, the ACI alone would almost never be selected even if it were available.[10] Data suggest that the amount of carbon injection required to remove particular percentages of Hg is higher for units burning lignite coal. Thus, the costs and characteristics of the ACI+COHPAC retrofit available to units burning lignite coal are different from those available to units burning bituminous and subbituminous coals.[11]

[7] LNBs were found to always be the control of choice, before any unit would shift to SCR. Thus, EPMM was run with all units in a region with a $NO_x$ cap having LNBs already installed. The only retrofits simulated for $NO_x$ were the SCRs that still were economical after universal application of LNB. This same method was used in EPA's IPM model runs.

[8] In the case of Hg controls, units might also consider use of FGDs or FGD/SCRs in combination, because the model reflects how retrofits also reduce Hg emissions through "co-benefits."

[9] A COHPAC is a type of fabric filter that is installed on a unit downstream of a primary particle collector such as an electrostatic precipitator (ESP). It provides supplementary particle collection, and because of this, the COHPAC is smaller and cheaper than a fabric filter that would be necessary as the unit's primary particle collection device. When a COHPAC is used with an ACI, the carbon injection occurs between the primary collector and the COHPAC unit, and the COHPAC removes the carbon without it having mixed with the large volumes of fly ash. This reduces disposal costs and possible losses of revenues from fly ash sales. However, the COHPAC also (a) greatly reduces the amount of carbon that needs to be injected to achieve a given percentage removal (thus reducing operating costs of the Hg removal system), and (b) helps the ACI system achieve higher potential removal efficiencies than have typically been observed in ACI systems in the absence of any fabric filter.

[10] Modeling resources limit the number of types and combinations of retrofits that can be represented in any single model run. Consequently, it became important to reduce the number of control technology combinations without biasing cost results, and so ACI alone was not included in EPMM runs.

[11] There remains substantial uncertainty about the ability of an ACI+COHPAC or ACI+FF to achieve removal efficiencies in the range of 90% if the unit is burning subbituminous coal. Only one pilot test exists that has suggested this may be possible. This is considered one of the most uncertain of the EPMM assumptions regarding mercury control technology, and EPMM assumptions are on the optimistic end of the spectrum.

## Table IV-12. Cost and Characteristics of Control Technologies
(Costs are in 1999$)

| Retrofit | Reference Capital Cost* (\$/kW) | Reference Fixed O&M Cost* (\$/kW-yr) | Ref. Size (MW) | Scaling Ex-ponent | Variable Cost (\$/MWh) | Incremental Percent Removed "R" |
|---|---|---|---|---|---|---|
| Wet FGD | \$201.00 | \$8.00 | 500 | 0.60 | \$1.00 | $SO_2$: 90% |
| SCR | \$80.00 | \$0.53 | 243 | 0.35 | \$0.97 | $NO_x$: 95% |
| ACI (on existing FF units only) *for bituminous & subbituminous* | \$1.91 | \$0.77 | 250 | 0.35 | \$0.312 x (exp((1.1 x **R**)^1.7) -1) | Hg: 0% - 90% |
| ACI (on existing FF units only) *for lignite coal* | \$1.91 | \$0.77 | 250 | 0.35 | \$0.395 x (exp((1.8 x **R**)^1.8) -1) | Hg: 0% - 75% |
| ACI+COHPAC *for bituminous & subbituminous* | \$52.63 | \$0.96 | 250 | 0.35 | \$0.312 x (exp((1.1 x **R**)^1.7) -1) | Hg: 0% - 90% |
| ACI+COPAC *for lignite coal* | \$52.63 | \$0.96 | 250 | 0.35 | \$0.395 x (exp((1.8 x **R**)^1.8) -1) | Hg: 0% - 75% |

* Unit-Specific Cost = Reference Cost x (Reference Size/Unit MW)^(Scaling Exponent );
Maximum unit size for scaling is 500 MW for all technologies in table above.

EPMM has the capability to precisely adjust the percentage of Hg removal by an ACI or ACI+COHPAC retrofit to meet the needs of each unit. Rather than a fixed percentage removal (*e.g.*, either 60% removal or 90% removal), the ACI+COHPAC can remove anywhere between 0% and 90% for bituminous and subbituminous coals, and anywhere between 0% and 75% for lignite coals. This is why the variable cost in Table IV-12 is an equation rather than a fixed number, increasing at an increasing rate as the percent removal, **R**, rises towards its maximum. EPMM recognizes the flexibility of ACI+COHPAC retrofits and allows each unit to meet precisely the percent reduction that would be required under a MACT-type of control.

### *MERCURY CO-BENEFITS*

Table IV-13 shows the Hg co-benefits, or percent removal, assumed for each of the combinations of unit equipment before any ACI controls might be added. The values on the left of the slashes are the EPMM assumptions. These values were based primarily on EPRI's analysis of the 1999 ICR data, and were adjusted judgmentally to reflect more recent experience of EPRI and industry researchers. The values on the right of the slashes are the respective assumptions being used at present by EPA in the IPM model. The EPA values are presented here because they are one of the most significant issues contributing to the differences between EPA and EPMM findings.

**Table IV-13. Comparison of EPMM and EPA Hg Co-Benefits Assumptions (Percent Removal of Hg Relative to Inlet Hg)**

| Existing PM Collector | Existing $SO_2$ Controls | SCR | Bituminous * (EPMM / EPA) | Subbituminous * (EPMM / EPA) | Lignite * (EPMM / EPA) |
|---|---|---|---|---|---|
| FF | Dry FGD | no | 85 / 95 | 25 / 25 | 10 / 0 |
| | | yes | 90 / 95 | 25 / 25 | 10 / 0 |
| | Wet FGD | no | 85 / 97 | 75 / 73 | 40 / 44 |
| | | yes | 90 / 90 | 75 / 85 | 40 / 44 |
| | None | no | 75 / 89 | 65 / 73 | 10 / 0 |
| | | yes | 75 / 89 | 65 / 73 | 10 / 0 |
| CSESP | Dry FGD | no | 50 / 36 | 15 / 35 | 10 / 0 |
| | | yes | 85 / 36 | 15 / 35 | 10 / 0 |
| | Wet FGD | no | 60 / 66 | 35 / 16 | 35 / 44 |
| | | yes | 85 / 90 | 35 / 66 | 35 / 44 |
| | None | no | 35 / 36 | 20 / 3 | 10 / 0 |
| | | yes | 35 / 36 | 20 / 3 | 10 / 0 |
| HSESP | Dry FGD | no | *n/a* / 40 | *n/a* / 15 | *n/a* / 0 |
| | | yes | *n/a* / 40 | *n/a* / 15 | *n/a* / 0 |
| | Wet FGD | no | 55 / 42 | 30 / 20 | 30 / 0 |
| | | yes | 85 / 90 | 30 / 25 | 30 / 0 |
| | None | no | 20 / 10 | 0 / 6 | 0 / 0 |
| | | yes | 20 / 10 | 0 / 10 | 0 / 0 |

*Percent removals for EPA are sourced from IPM Model Documentation v.2.1.6, Attachment K

# V. DETAILS OF SCENARIO SPECIFICATIONS

***BASE CASE***

The Base Case includes existing $SO_2$ (Title IV) and $NO_x$ (SIP Call) regulations, as well as state regulations. Regulations for the following states are included: North Carolina, Connecticut, Massachusetts, New Hampshire, New York, Missouri, Illinois, Maine, and Texas. All of these regulations relate to $SO_2$ and/or $NO_x$. Connecticut also includes an emission limit for Hg. In addition to Title IV, the Western Regional Air Partnership (WRAP) has $SO_2$ caps for nine states beginning in 2018.[12] Table V-1 shows the emissions caps for the non-state programs that are applied in the Base Case.

**Table V-1. Base Case Emissions Caps**
(Short Tons)

| | $SO_2$ | | $NO_x$ |
|---|---|---|---|
| **Year** | **US** | **WRAP** | **SIP Call** |
| **2004** | 9,480,000 | | 517,199 |
| **2008** | 9,480,000 | | 517,199 |
| **2010** | 8,950,000 | | 517,199 |
| **2012** | 8,950,000 | | 517,199 |
| **2015** | 8,950,000 | | 517,199 |
| **2018** | 8,950,000 | 271,000 | 517,199 |
| **2020** | 8,950,000 | 271,000 | 517,199 |

***IAQR ONLY***

The IAQR Only case layers that proposed rule's $SO_2$ and $NO_x$ regulations on top of the existing regulations in the Base Case, beginning in 2010. (However, given the way the $SO_2$ cap is proposed, banking of $SO_2$ prior to 2010 can be used to meet the IAQR $SO_2$ cap that is first implemented in 2010.) The simulation of the IAQR caps was performed for a geographic area slightly different from that specified in the proposed rule. The $NO_x$ rules were applied to the states included in the East Region of the Clear Skies Act (CSA). This required some modification of the $NO_x$ caps that were modeled. Specifically, tonnage for western Missouri, which is not included in the East Region of the CSA, was netted from the capped amounts of 1.6 million tons and 1.3 millions tons in 2010 and 2015, respectively. Tonnage was added for Florida, Maine, New Hampshire, Rhode

[12] The nine states are: Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah and Wyoming.

Island, Vermont, and the western portion of Texas, as these areas are part of the East Region of CSA, but not part of the IAQR region. The tons added (subtracted) were based on an emission rate of 0.150 lbs/MMBtu in 2010 and 0.125 lbs/MMBtu in 2015.[13] This resulted in slightly higher $NO_x$ caps of approximately 1.7 million tons in 2010 and 1.4 million tons in 2015.

$SO_2$ was modeled with a single national cap. However, emissions for the District of Columbia and the 28 states included in the IAQR were applied using the ratios in the rule.[14] To compute a single national cap that allows trading at a national level, existing Title IV Phase II allowances were used for each state. States included in the IAQR had their allowances divided by two for the period 2010 through 2014 and divided by three for 2015 and later years. This resulted in a national cap of approximately 5.1 million tons in 2010 and 3.8 million tons in 2015.[15] Table V-2 below shows the modeled national and regional caps applied in the IAQR Only scenario.

**Table V-2. IAQR Only Emissions Caps**
(Short Tons)

| | $SO_2$ | | $NO_x$ | |
|---|---|---|---|---|
| **Year** | **US** | **WRAP** | **SIP Call** | **IAQR** |
| **2004** | 9,480,000 | | 517,199 | |
| **2008** | 9,480,000 | | 517,199 | |
| **2010** | 5,086,400 | | 517,199 | 1,675,968 |
| **2012** | 5,086,400 | | 517,199 | 1,675,968 |
| **2015** | 3,798,600 | | 517,199 | 1,363,307 |
| **2018** | 3,798,600 | 271,000 | 517,199 | 1,363,307 |
| **2020** | 3,798,600 | 271,000 | 517,199 | 1,363,307 |

### *IAQR + Hg CAP*

The IAQR + Hg Cap case begins with the IAQR Only caps and adds a cap on Hg emissions as well. The cap on Hg emissions begins in 2010 with a cap of 34 tons, which is then reduced to 15 tons in 2015. Table V-3 shows the modeled national and regional caps applied in the IAQR + Hg Cap case.

[13] IAQR Proposed Rule, p. 108.
[14] IAQR Rule, p. 316-317. "(1) Pre-2010 allowances to be used at a one-to-one ratio; (2) 2010 through 2014 allowances to be used at a two-to-one; and (3) 2015 and later allowances to be used at a three-to-one ratio.
[15] Of the national cap, states in the IAQR comprised nearly 3.9 million tons of the 5.1 million ton cap in 2010 and 2.6 million tons of the 3.8 million ton cap.

**Table V-3. IAQR + Hg Cap Emissions Caps**
(Short Tons)

| Year | $SO_2$ US | $SO_2$ WRAP | $NO_x$ SIP Call | $NO_x$ IAQR | Hg |
|---|---|---|---|---|---|
| **2004** | 9,480,000 | | 517,199 | | |
| **2008** | 9,480,000 | | 517,199 | | |
| **2010** | 5,086,400 | | 517,199 | 1,675,968 | 34.0 |
| **2012** | 5,086,400 | | 517,199 | 1,675,968 | 34.0 |
| **2015** | 3,798,600 | | 517,199 | 1,363,307 | 34.0 |
| **2018** | 3,798,600 | 271,000 | 517,199 | 1,363,307 | 15.0 |
| **2020** | 3,798,600 | 271,000 | 517,199 | 1,363,307 | 15.0 |

The Hg Cap & Trade policy proposal also includes a feature where units may borrow against their future Hg allocations at a maximum permit price of $2,187.50 per ounce ($35,000 per pound in 2004 dollars). This feature, often called a “safety valve,” was added to provide stability in Hg allowance prices. Although it may dampen Hg allowance price volatility, its specific formulation in the proposed rule makes it unlikely to actually cap the equilibrium market price of Hg allowances.[16] Another reason this feature is unlikely to cap the market price of Hg allowances is because the proposed supplemental rule authorizes each state to decide whether or not to allow this “borrowing” at a maximum price. Current politics suggest that many states would not avail themselves of this feature.

Nevertheless, this feature was considered in the EPMM Hg Cap & Trade simulations. However, EPMM projected that equilibrium allowance prices are unlikely to exceed the maximum price of $35,000/lb. This policy scenario was run under a range of assumptions about the rate of technological improvement in the currently immature Hg control technology based on activate carbon injection. Costs of the technology were assumed to decrease by annual rates of 0% (i.e., no technological improvement at all),

[16] The term “safety valve” was originally introduced in greenhouse gas policy proposals, where it was formulated as a true price cap because it would not require that allowances obtained at the safety valve price be deducted from future allowance allocations. Its formulation in the Hg Cap & Trade proposal does not create a true cap on allowance prices, however, because any extra Hg allowances obtained under this clause must be deducted from future allocations. (Additionally, this would be a deduction from the individual company’s own allocation, rather than a reduction in future national caps, implying that the entire future burden of using such allowances will be imposed on the company that wishes to use this feature.) This places a practical limit on the quantity available, and any use of such allowances in a given year will imply increasingly higher allowance prices in later years from which the allowances have been deducted. Thus, the Hg “safety valve” feature may function as an emergency source of a few marginal allowances for individual companies. However, it is unlikely to cap the market price of Hg allowances in the situation of concern, where the marginal cost of achieving the national cap turns out to be substantially higher than $35,000/lb.

1.5%, 2.5%, and 4.0% (the last of these rates was applied only to the variable operating cost component.) EPMM projects that Hg allowance prices would not exceed the safety valve price except in the case where there is no technological improvement at all over the next 16 years, and even then the exceedance would not occur until after 2018. In all the other years and in all the other cases, EPMM finds no equilibrium demand to use the safety valve feature.

The alternative assumptions about rates of technological improvement had no substantial effect on projected Hg emissions over time, or on markets and compliance methods for other emissions. The specific numerical results presented in this paper are from the zero technological change case.

***IAQR + Hg MACT***

The IAQR + Hg MACT case also begins with the IAQR Only caps and then adds an emissions rate limit for Hg beginning in 2008. The relevant rate limit is based on the rank of coal burned by a unit. The rate limit for bituminous coal is 2.0 pounds per trillion Btu; the rate limit for subbituminous coal is 5.8 pounds per trillion Btu; and the rate limit for lignite coal is 9.2 pounds per trillion Btu. For units that blend coals, the modeling requires that the respective rate limit for each coal must be met. For example, if a unit consumes bituminous and subbituminous coals in equal share, the model requires that the emissions rate limit on the bituminous portion is 2.0 pounds per trillion Btu and 5.6 pounds per trillion Btu on the subbituminous portion. Each unit must meet these constraints, and no trading is allowed.

# VI. RESULTS OF SCENARIOS

Several important caveats are warranted regarding the results of the scenarios. In particular, the model runs presented here have not assigned any limitations or constraints on the numbers or aggregate capacity of retrofits that may be installed in any year. No lead times have been imposed for retrofits either, so that the model is free to start installing new control technologies such as FGD even in the 2004 model year. In reality, only FGDs that are already in the advanced planning phases (of which there are very few) could possibly be in place before 2007. To the extent that some scenarios project relatively large numbers of FGDs prior to 2008, model results must be viewed as unrealistic. Similarly, if the aggregate quantity of retrofits of any type of technology becomes large in a short period of time, model results must be interpreted with great caution. Finally, the modeling places no limit on when that the mercury control technology based on activated carbon injection (ACI) will be commercially available on a widespread basis. Model scenarios that indicate a need for large quantities of retrofits of this technology within the next few years should be viewed as potentially unrealistic.

Figure VI-1 shows the projected trends in total national emissions of Hg under each of the policies simulated with EPMM.

Figure VI-1 reveals that co-benefits from FGD and SCRs projected under the IAQR Only scenario are projected to induce a reduction relative to the Reference Case of about 7 tons by 2010, bringing projected total Hg emissions to 40 tons in 2010. These are called "co-benefits" because they occur without any specific policy constraints on Hg emissions or emissions rates. EPMM's projection of 40 tons as the "co-benefits" level contrasts to the EPA estimate of 34 tons by 2010 due to the IAQR alone.

Because EPMM's projected co-benefits level of Hg emissions is higher than 34 tons, the Hg Cap & Trade scenario requires an additional 6 tons of Hg reduction by 2010. This is almost as large of an extra reduction as the co-benefits-based reduction. The result is that emissions are projected to fall just to the Phase I cap level at first. However, over the course of the Hg Cap & Trade's Phase I (2010-2017), Hg emissions do continue to decline gradually, to about 30 tons per year in the 2015-2017 period. A bank of Hg allowances is thus projected to accumulate to a level of about 18 tons at the beginning of Phase II in 2018. This bank is projected to be entirely used up by 2020, and projected Hg emissions reach the Phase II cap of 15 tons by 2020.

The Hg MACT, in contrast, reduces emissions sooner, but only reduces them to about 32 tons. After the initial introduction of the MACT constraints in 2008, there is only a small amount of further reduction in Hg through 2020. The model indicates that the Hg Cap & Trade proposal will produce lower Hg emissions than the Hg MACT proposal after about 2012.

## Figure VI-1.  Projected Trends in National Hg Emissions

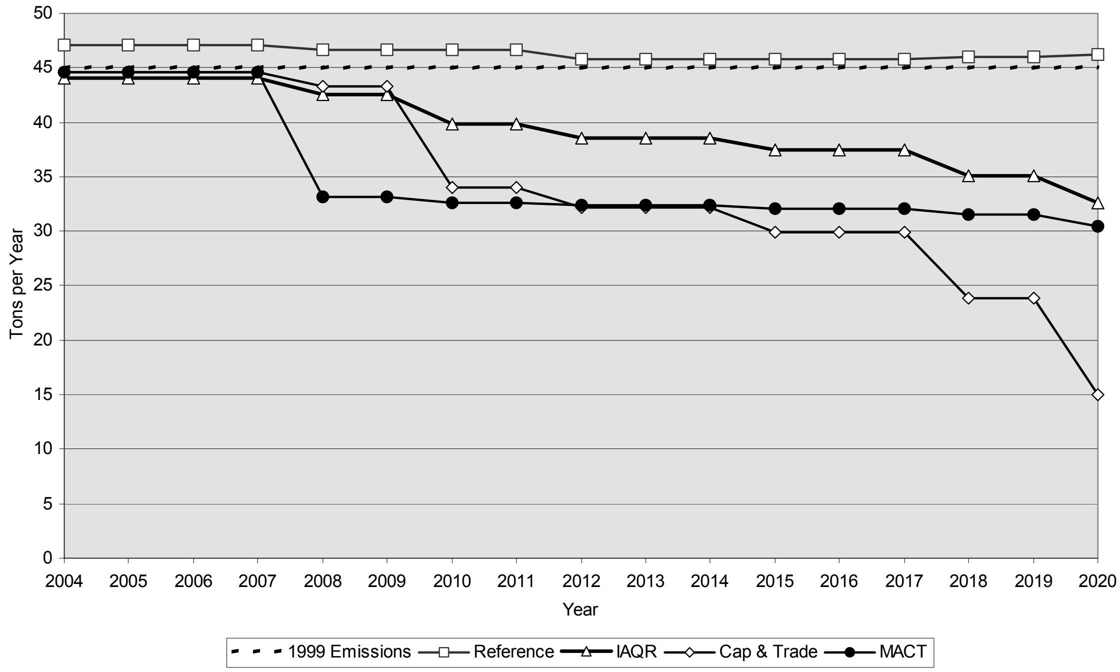


Table VI-1 shows the costs of each scenario relative to the Base Case. The Hg Cap & Trade case costs $2 billion more than the IAQR Only (on a net present value basis in 1999 dollars), while the Hg MACT case costs $10 billion more than the IAQR Only case. Thus the Hg Cap & Trade policy is projected to cost one-fifth what the Hg MACT policy would cost, despite the fact that the proposed Hg Cap & Trade policy would ultimately produce much lower Hg emissions than the proposed MACT policy. At an aggregate level, the main benefit of the Hg MACT appears to be that emissions would be lower for a few years before the Hg Cap & Trade would produce greater reductions.

**Table VI-1. Annual and Present Value of Scenario Costs Incremental to Base Case (billions of dollars, $1999)**

| Year | IAQR | MACT | Cap & Trade |
|---|---|---|---|
| 2004 | $0.8 | $0.7 | $0.7 |
| 2008 | 1.2 | 4.4 | 0.8 |
| 2010 | 2.1 | 4.4 | 2.5 |
| 2012 | 2.5 | 4.3 | 3.2 |
| 2015 | 3.3 | 5.0 | 4.0 |
| 2018 | 4.5 | 5.3 | 5.3 |
| 2020 | 7.0 | 6.8 | 8.1 |
| **Present Value** | **$17.7** | **$27.8** | **$19.7** |
| ***Incremental Present Value Cost of Adding Hg Provisions on Top of IAQR:*** | | ***$10.1*** | ***$2.0*** |

### *BASE CASE*

As Table VI-2 shows, in the Base Case, 13 GW install wet FGDs by 2020 and 29 GW install SCRs by 2020. As a result of existing state regulations, 1 GW install ACI, either with an existing fabric filter (FF) or with a retrofitted COHPAC, by 2020. The FGDs are installed across several years reflecting the need for greater controls as demand grows and the $SO_2$ bank is drawn down. The SCR installations are focused in 2004 to meet the $NO_x$ SIP Call.[17] Table VI-3 shows the Base Case emissions of $SO_2$, $NO_x$, and Hg by model region.

[17] The 19 GW of SCRs in 2004 are EPMM's estimated SIP Call compliance needs beyond the 87 GW of SCRs and SNCRs that are assumed to be installed before the end of 2004, and which are in the "existing" technology before EPMM starts its simulation.

**Table VI-2. Base Case Retrofits**
(Megawatts)

| Year | Wet FGD | Coal SCR | ACI+FF or +COHPAC |
|---|---|---|---|
| **2004** | 563 | 18,508 | 979 |
| **2008** | 2,671 | 2,606 | 72 |
| **2010** | 1,913 | 252 | 0 |
| **2012** | 3,613 | 385 | 0 |
| **2015** | 0 | 0 | 0 |
| **2018** | 4,492 | 394 | 0 |
| **2020** | 95 | 6,575 | 0 |
| **Total** | 13,346 | 28,720 | 1,050 |

## Table VI-3. Base Case Coal Plant Emissions

($SO_2$ in thousands of short tons, $NO_x$ and Hg in short tons)

| | 2004 | | | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|---|---|---|
| **Region** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** |
| NEPP | 82 | 12,708 | 0.27 | 33 | 12,088 | 0.20 | 34 | 12,736 | 0.20 |
| NYISO, West | 82 | 28,315 | 0.33 | 97 | 27,187 | 0.40 | 86 | 26,923 | 0.35 |
| NYISO, Capital | - | - | - | - | - | - | - | - | - |
| NYISO, Hudson Valley | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.09 |
| NYISO, New York City | - | - | - | - | - | - | - | - | - |
| NYISO, Long Island | - | - | - | - | - | - | - | - | - |
| PJM Eastern | 258 | 28,217 | 1.00 | 196 | 30,959 | 0.88 | 155 | 34,850 | 0.80 |
| PJM Central | 471 | 32,602 | 1.29 | 360 | 34,801 | 1.15 | 283 | 37,980 | 1.01 |
| PJM Western | 821 | 68,421 | 2.81 | 716 | 68,739 | 2.67 | 570 | 72,234 | 2.42 |
| VACAR | 1,274 | 166,752 | 3.74 | 802 | 138,649 | 2.68 | 756 | 154,066 | 2.53 |
| SOU | 1,157 | 207,544 | 3.95 | 1,150 | 209,845 | 3.95 | 1,004 | 221,496 | 3.59 |
| Entergy | 200 | 74,458 | 1.27 | 201 | 75,763 | 1.28 | 201 | 75,763 | 1.28 |
| TVA | 428 | 95,900 | 1.62 | 420 | 96,267 | 1.53 | 399 | 102,172 | 1.59 |
| FRCC | 184 | 69,531 | 0.98 | 187 | 83,246 | 0.94 | 178 | 100,125 | 1.04 |
| ECAR | 2,805 | 554,807 | 11.08 | 2,559 | 577,281 | 11.84 | 2,481 | 527,900 | 11.68 |
| Com Ed | 115 | 50,287 | 0.73 | 133 | 57,570 | 0.85 | 169 | 60,935 | 1.08 |
| South MAIN | 405 | 99,361 | 2.11 | 404 | 103,045 | 2.14 | 441 | 106,584 | 2.25 |
| WIUM | 178 | 79,639 | 1.09 | 178 | 79,711 | 1.09 | 184 | 82,085 | 1.12 |
| MAPP | 471 | 251,551 | 3.95 | 498 | 259,567 | 4.08 | 484 | 267,747 | 4.11 |
| SPP North | 316 | 110,457 | 1.35 | 199 | 110,608 | 1.41 | 223 | 118,887 | 1.51 |
| SPP South | 251 | 89,773 | 2.01 | 251 | 89,773 | 2.01 | 251 | 89,773 | 2.01 |
| ERCOT | 374 | 61,069 | 3.39 | 409 | 69,550 | 3.45 | 452 | 104,695 | 3.72 |
| WA, OR | 19 | 25,367 | 0.28 | 19 | 25,367 | 0.28 | 13 | 28,132 | 0.33 |
| ID,UT,MT, parts of NV,WY | 82 | 91,779 | 0.87 | 83 | 93,395 | 0.88 | 71 | 104,983 | 0.92 |
| Northern California | - | - | - | - | - | - | - | - | - |
| Southern California and Nevada | - | - | - | - | - | - | - | - | - |
| Arizona and New Mexico | 198 | 133,000 | 1.63 | 198 | 133,000 | 1.63 | 111 | 137,696 | 1.42 |
| RMPP | 161 | 116,351 | 1.23 | 161 | 116,351 | 1.23 | 113 | 115,075 | 1.19 |
| Total | 10,357 | 2,454,701 | 47.08 | 9,278 | 2,499,578 | 46.65 | 8,685 | 2,589,650 | 46.23 |

*IAQR ONLY*

Table VI-4 shows that in the IAQR Only case, when run with the standard EPMM assumptions, 118 GW install wet FGDs by 2020, and 64 GW install SCRs by 2020.[18] Once again, there is the 1 GW of ACI+COHPAC added by 2020 due to existing state regulations. The FGDs are installed in early years to build up the bank before the tighter IAQR $SO_2$ cap, and then the bank is drawn down to comply with the tighter IAQR $SO_2$ caps. Significant amounts of retrofits are also put on in the latter years to address limit emissions in the face of increasing demand, a tighter Phase II cap and a depleted $SO_2$ bank. SCRs are put on more evenly over the study period, first to meet the $NO_x$ SIP Call, then to meet Phase I of the IAQR $NO_x$ caps and finally to meet the tighter Phase II IAQR $NO_x$ caps.

**Table VI-4. IAQR Only – Retrofits**
(Megawatts)

| Year | Wet FGD | Coal SCR | ACI+FF or +COHPAC |
|---|---|---|---|
| **2004** | 6,185 | 18,508 | 1,050 |
| **2008** | 14,444 | 2,921 | 0 |
| **2010** | 18,502 | 6,980 | 0 |
| **2012** | 9,843 | 10,103 | 0 |
| **2015** | 770 | 13,477 | 0 |
| **2018** | 21,997 | 7,190 | 0 |
| **2020** | 46,193 | 4,465 | 0 |
| **Total** | 117,934 | 63,644 | 1,050 |

Table VI-5 shows the emissions for 2004, 2010, and 2020 for the IAQR Only Case. As a result of the IAQR, $SO_2$ and $NO_x$ emissions fall throughout the study period. The co-benefits of the FGD and SCR retrofits cause Hg emissions to fall throughout the modeled time period. Although the "co-benefits level" usually refers to emissions under the IAQR Only in 2010, they continue to reduce Hg emissions after that. Hg emissions fall from Base Case levels of about 47 tons to 40 tons in 2010, and by another 7 tons to 33 tons in 2020.

[18] Several sensitivity cases were also run for the IAQR Only scenario. In one of these, new FGDs were prevented until after 2008. In another, no blending of subbituminous coals was permitted with bituminous coals. In the third, both constraints were applied together. The effect of these constraints was to increase the number of FGD retrofits needed by 2010. Whereas there are about 39 GW of added FGD cumulatively by 2010 in the base run (Table VI-4), the quantity of additional FGD that was desired in 2010 rose to 64 GW in the third sensitivity case. This higher level of retrofitting may not be feasible, but the sensitivity runs indicate that the demand for retrofits (and hence the difficulty of achieving compliance with even Phase I of the IAQR) is quite dependent on assumptions about the ease with which coal switching and early FGD installations can be achieved.

## Table VI-5. IAQR Only – Coal Plant Emissions

($SO_2$ in thousands of short tons, $NO_x$ and Hg in short tons)

| | 2004 | | | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|---|---|---|
| Region | $SO_2$ | $NO_x$ | Hg | $SO_2$ | $NO_x$ | Hg | $SO_2$ | $NO_x$ | Hg |
| NEPP | 82 | 12,888 | 0.27 | 31 | 11,745 | 0.19 | 33 | 12,582 | 0.20 |
| NYISO, West | 85 | 28,014 | 0.34 | 80 | 25,269 | 0.32 | 76 | 24,975 | 0.30 |
| NYISO, Capital | - | - | - | - | - | - | - | - | - |
| NYISO, Hudson Valley | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.09 |
| NYISO, New York City | - | - | - | - | - | - | - | - | - |
| NYISO, Long Island | - | - | - | - | - | - | - | - | - |
| PJM Eastern | 117 | 28,217 | 0.54 | 108 | 30,549 | 0.56 | 88 | 29,215 | 0.51 |
| PJM Central | 75 | 32,594 | 0.45 | 60 | 25,885 | 0.46 | 67 | 26,989 | 0.49 |
| PJM Western | 228 | 67,918 | 1.31 | 174 | 60,682 | 1.36 | 117 | 47,585 | 1.02 |
| VACAR | 1,169 | 165,755 | 3.64 | 643 | 138,497 | 2.35 | 359 | 140,876 | 1.64 |
| SOU | 1,181 | 207,406 | 3.95 | 610 | 195,935 | 2.56 | 202 | 151,246 | 1.62 |
| Entergy | 200 | 74,458 | 1.27 | 201 | 75,763 | 1.28 | 103 | 76,600 | 1.15 |
| TVA | 428 | 95,900 | 1.62 | 366 | 94,162 | 1.39 | 276 | 69,901 | 1.21 |
| FRCC | 170 | 69,531 | 0.95 | 181 | 83,241 | 0.94 | 90 | 86,677 | 0.74 |
| ECAR | 2,413 | 553,878 | 10.88 | 1,742 | 513,229 | 10.18 | 977 | 359,803 | 6.74 |
| Com Ed | 116 | 50,982 | 0.74 | 113 | 42,864 | 0.72 | 116 | 33,571 | 0.84 |
| South MAIN | 413 | 100,511 | 2.13 | 357 | 88,771 | 1.96 | 150 | 67,468 | 1.27 |
| WIUM | 173 | 77,631 | 1.07 | 163 | 73,555 | 1.02 | 105 | 55,745 | 0.90 |
| MAPP | 462 | 250,913 | 3.99 | 435 | 241,635 | 3.82 | 243 | 221,152 | 3.53 |
| SPP North | 193 | 109,699 | 1.39 | 157 | 109,052 | 1.40 | 121 | 115,905 | 1.38 |
| SPP South | 251 | 89,773 | 2.01 | 251 | 89,773 | 2.01 | 150 | 90,471 | 1.84 |
| ERCOT | 374 | 61,069 | 3.39 | 269 | 65,182 | 3.28 | 204 | 100,154 | 3.36 |
| WA, OR | 23 | 25,367 | 0.33 | 21 | 25,367 | 0.30 | 6 | 27,447 | 0.28 |
| ID,UT,MT, parts of NV,WY | 82 | 91,779 | 0.87 | 80 | 93,152 | 0.90 | 71 | 107,290 | 0.95 |
| Northern California | - | - | - | - | - | - | - | - | - |
| Southern California and Nevada | - | - | - | - | - | - | - | - | - |
| Arizona and New Mexico | 198 | 133,000 | 1.63 | 181 | 132,915 | 1.57 | 112 | 137,864 | 1.42 |
| RMPP | 161 | 116,351 | 1.23 | 159 | 116,277 | 1.24 | 113 | 115,932 | 1.19 |
| Total | 8,617 | 2,450,449 | 44.10 | 6,407 | 2,340,312 | 39.89 | 3,803 | 2,106,262 | 32.66 |

### *IAQR + Hg CAP & TRADE*

Table VI-6 shows that in the IAQR + Hg Cap & Trade Case, 109 GW install wet FGDs by 2020, 61 GW install SCRs by 2020, and 107 GW install ACI+COHPAC by 2020. FGD installations are driven by the tightening $SO_2$ caps under IAQR and the co-benefits for Hg reduction that can be achieved from FGD/SCR combinations. SCR installations are driven by the tightening $NO_x$ caps under the IAQR and also the co-benefits that can be achieved from FGD/SCR combination. Beginning in 2010, ACI+COHPAC are installed to meet the Hg cap. There is also an increase in the number of FGDs and SCRs that are installed by 2010 compared to the IAQR Only case. These are installations that occur *earlier* than in the IAQR Only and they occur earlier due to the value of their Hg co-benefits created by the addition of the Hg cap in this scenario.[19]

**Table VI-6. IAQR + Hg Cap & Trade - Retrofits**
(Megawatts)

| Year | Wet FGD | Coal SCR | ACI+FF or +COHPAC |
|---|---|---|---|
| **2004** | 1,315 | 18,508 | 1,050 |
| **2008** | 8,159 | 3,005 | 1 |
| **2010** | 35,421 | 11,341 | 14,675 |
| **2012** | 11,289 | 11,065 | 3,085 |
| **2015** | 3,361 | 1,994 | 12,270 |
| **2018** | 15,975 | 7,704 | 25,202 |
| **2020** | 33,662 | 7,031 | 50,562 |
| **Total** | 109,181 | 60,648 | 106,844 |

The Hg Cap & Trade case was run with a variety of assumptions about the rate of technological improvement in the Hg control technology. The cases considered included no technological improvement at all (0% rate of change), a 1.5% per year reduction in capital and O&M costs, a 2.5% per year reduction in capital and O&M costs, a 2.5% per year reduction in variable O&M costs only, and a 4.0% per year reduction in variable O&M costs only. The most apparent effect of technological change assumption was to reduce the marginal cost of control (i.e., the allowance prices). In all cases except for 0% technological improvement in 2020, the projected allowance prices remained below the

[19] These results reflect the EPMM base assumptions that do not constrain the ability to install an unlimited quantity of retrofits before 2008, and which allow blending of subbituminous coal up to 50% with no capital or operating cost impact (other than the cost of the coal itself). No sensitivity cases on these flexibilities were run for the Hg Cap & Trade scenario, or for the MACT scenario.

"safety valve" price of $35,000/lb (2004$). Table VI-7 presents the Hg allowance price projections for each of the cases, in 1999 dollars.[20]

**Table VI-7. Projected Hg Allowance Prices Under Alternative Assumptions of Rates of Improvement in Hg Control Technology**
($/lb Hg, in 1999$)

| | Annual Rate of Technological Improvement on Activated Carbon Injection Control Methods | | | | |
|---|---|---|---|---|---|
| | 0% | 1.5% | 2.5% | 2.5% | 4.0% |
| Year | | Capital and O&M | Capital and O&M | Variable O&M only | Variable O&M only |
| 2010 | $22,108 | $21,850 | $22,345 | $20,854 | $20,090 |
| 2012 | $21,654 | $19,623 | $17,904 | $18,727 | $17,420 |
| 2015 | $25,826 | $23,404 | $21,353 | $22,335 | $20,775 |
| 2018 | $30,824 | $27,933 | $25,485 | $26,657 | $24,796 |
| 2020 | $37,285 | $28,495 | $23,611 | $32,536 | $30,951 |

In all of the technological change cases, Hg emissions meet the Phase I cap of 34 tons in 2010 and the Phase II cap of 15 tons in 2020. There were only minimal differences in the pattern of retrofits, emissions, or banking over time due to the alternative assumptions about rates of technological change. Table VI-8 shows the emissions for 2004, 2010, and 2020 for the IAQR + Hg Cap & Trade case for the 0% technological improvement case, which was the case that was used to develop inputs for the TEAM deposition model.

[20] The safety valve price in 1999 dollars is about $31,500.

**Table VI-8. IAQR + Hg Cap & Trade - Coal Plant Emissions**
($SO_2$ in thousands of short tons, $NO_x$ and Hg in short tons)

| | 2004 | | | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|---|---|---|
| **Region** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** |
| NEPP | 82 | 12,889 | 0.27 | 30 | 11,580 | 0.19 | 33 | 12,470 | 0.20 |
| NYISO, West | 85 | 28,145 | 0.34 | 80 | 26,181 | 0.32 | 74 | 25,025 | 0.19 |
| NYISO, Capital | - | - | - | - | - | - | - | - | - |
| NYISO, Hudson Valley | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.09 | 19 | 6,823 | 0.07 |
| NYISO, New York City | - | - | - | - | - | - | - | - | - |
| NYISO, Long Island | - | - | - | - | - | - | - | - | - |
| PJM Eastern | 117 | 28,217 | 0.54 | 109 | 25,880 | 0.47 | 78 | 24,788 | 0.38 |
| PJM Central | 133 | 32,431 | 0.43 | 69 | 22,308 | 0.36 | 65 | 22,832 | 0.38 |
| PJM Western | 289 | 68,027 | 1.39 | 193 | 44,305 | 1.03 | 104 | 37,973 | 0.79 |
| VACAR | 1,170 | 165,987 | 3.65 | 636 | 137,201 | 2.30 | 353 | 125,167 | 1.39 |
| SOU | 1,224 | 207,406 | 4.05 | 543 | 184,666 | 2.35 | 178 | 131,931 | 1.40 |
| Entergy | 200 | 74,458 | 1.27 | 185 | 69,190 | 1.07 | 198 | 75,791 | 0.13 |
| TVA | 428 | 95,900 | 1.62 | 319 | 94,203 | 1.34 | 190 | 75,442 | 0.68 |
| FRCC | 184 | 69,531 | 0.98 | 181 | 71,439 | 0.78 | 79 | 80,630 | 0.63 |
| ECAR | 2,505 | 554,208 | 11.12 | 1,604 | 522,226 | 8.31 | 837 | 373,163 | 4.16 |
| Com Ed | 116 | 51,047 | 0.74 | 107 | 43,904 | 0.68 | 134 | 54,370 | 0.25 |
| South MAIN | 425 | 100,553 | 2.16 | 325 | 87,008 | 1.78 | 174 | 61,930 | 0.46 |
| WIUM | 173 | 77,683 | 1.07 | 163 | 72,588 | 1.00 | 105 | 61,738 | 0.24 |
| MAPP | 462 | 250,808 | 3.99 | 416 | 239,276 | 2.92 | 297 | 238,862 | 0.86 |
| SPP North | 194 | 109,777 | 1.39 | 154 | 108,962 | 1.35 | 122 | 115,823 | 0.30 |
| SPP South | 251 | 89,773 | 2.01 | 251 | 89,773 | 1.40 | 251 | 89,773 | 0.37 |
| ERCOT | 374 | 61,069 | 3.39 | 255 | 65,035 | 2.77 | 249 | 98,566 | 1.11 |
| WA, OR | 23 | 25,367 | 0.33 | 19 | 24,535 | 0.27 | 6 | 27,229 | 0.05 |
| ID,UT,MT, parts of NV,WY | 82 | 91,779 | 0.87 | 80 | 93,371 | 0.60 | 69 | 105,148 | 0.31 |
| Northern California | - | - | - | - | - | - | - | - | - |
| Southern California and Nevada | - | - | - | - | - | - | - | - | - |
| Arizona and New Mexico | 198 | 133,000 | 1.63 | 168 | 132,915 | 1.43 | 97 | 135,827 | 0.44 |
| RMPP | 161 | 116,351 | 1.23 | 159 | 116,277 | 1.19 | 128 | 115,218 | 0.19 |
| Total | 8,900 | 2,451,218 | 44.58 | 6,071 | 2,289,635 | 34.00 | 3,837 | 2,096,517 | 15.00 |

*IAQR + Hg MACT*

As shown in Table VI-9, in the IAQR + Hg MACT Case, 98 GW install wet FGDs by 2020, 66 GW install SCRs by 2020, and 67 GW install ACI+COHPAC by 2020.[21] Most of the ACI+COHPAC installations appear in the 2008 model year when the MACT takes effect.[22]

This scenario indicates that the Hg MACT proposal would require a remarkable amount retrofitting within a very short time frame. Most of the 64 GW of ACI+FF in 2008 occurs on different units that those retrofitting the 67 GW of FGD. This means that compliance with the MACT would entail about 120 GW, or 40 percent of all coal-fired capacity, making some major form of retrofit in the period of time just prior to 2008 (only 3 years from now). These are quantities necessary to comply, but may reflect infeasible rates of retrofit and use of a still immature technology that may not be available on this scale by 2007. EPMM runs did not constrain rates of retrofitting or dates of full commercial availability for the ACI-based technology.

**Table VI-9. IAQR + Hg MACT – Retrofits**
(Megawatts)

| Year | Wet FGD | Coal SCR | ACI+FF or +COHPAC |
|---|---|---|---|
| **2004** | 1,309 | 18,508 | 1,072 |
| **2008** | 67,430 | 25,957 | 64,039 |
| **2010** | 1,488 | 2,207 | 1,623 |
| **2012** | 2,661 | 3,061 | 74 |
| **2015** | 2,090 | 3,336 | 21 |
| **2018** | 4,212 | 2,422 | 0 |
| **2020** | 18,211 | 10,139 | 0 |
| **Total** | 97,400 | 65,630 | 66,829 |

Table VI-10 shows the emissions for 2004, 2010, and 2020 for the IAQR + Hg MACT case. As a result of the IAQR, $SO_2$ and $NO_x$ emissions fall throughout the study period. Hg emissions decline significantly in 2008 when the Hg MACT takes effect. Further Hg reductions after 2008 are the result of co-benefits from FGD and SCR installations to meet stricter $SO_2$ and $NO_x$ caps.

[21] These results reflect the EPMM base assumptions that do not constrain the ability to install an unlimited quantity of retrofits before 2008, and which allow blending of subbituminous coal up to 50% with no capital or operating cost impact (other than the cost of the coal itself). No sensitivity cases on these flexibilities were run for the Hg Cap & Trade scenario, or for the MACT scenario.

[22] Although EPMM assigns this large pulse of retrofits to 2008, they would really have to occur before the end of 2007. One of the idealizations of the model is that the retrofits can be installed "instantly" if they become essential. The model is effectively installing them all at the instant that 2008 begins.

**Table VI-10. IAQR + Hg MACT - Coal Plant Emissions**
($SO_2$ in thousands of short tons, $NO_x$ and Hg in short tons)

| | 2004 | | | 2010 | | | 2020 | | |
|---|---|---|---|---|---|---|---|---|---|
| **Region** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** | **$SO_2$** | **$NO_x$** | **Hg** |
| NEPP | 82 | 12,888 | 0.27 | 33 | 10,723 | 0.13 | 33 | 10,723 | 0.13 |
| NYISO, West | 85 | 28,145 | 0.34 | 80 | 24,940 | 0.18 | 74 | 24,086 | 0.16 |
| NYISO, Capital | - | - | - | - | - | - | - | - | - |
| NYISO, Hudson Valley | 26 | 6,815 | 0.09 | 26 | 6,815 | 0.05 | 26 | 6,815 | 0.05 |
| NYISO, New York City | - | - | - | - | - | - | - | - | - |
| NYISO, Long Island | - | - | - | - | - | - | - | - | - |
| PJM Eastern | 117 | 28,217 | 0.54 | 68 | 19,657 | 0.25 | 85 | 25,115 | 0.37 |
| PJM Central | 133 | 32,431 | 0.43 | 69 | 24,075 | 0.30 | 63 | 20,268 | 0.34 |
| PJM Western | 289 | 68,027 | 1.39 | 124 | 38,761 | 0.69 | 128 | 39,053 | 0.75 |
| VACAR | 1,170 | 165,987 | 3.65 | 390 | 136,503 | 1.25 | 399 | 134,211 | 1.31 |
| SOU | 1,227 | 207,406 | 4.06 | 413 | 174,916 | 1.83 | 260 | 142,714 | 1.24 |
| Entergy | 200 | 74,458 | 1.27 | 201 | 75,763 | 1.28 | 161 | 61,685 | 1.23 |
| TVA | 428 | 95,900 | 1.62 | 326 | 96,397 | 0.85 | 276 | 90,451 | 0.78 |
| FRCC | 184 | 69,531 | 0.98 | 166 | 54,139 | 0.54 | 151 | 72,760 | 0.59 |
| ECAR | 2,502 | 554,199 | 11.12 | 1,218 | 477,642 | 7.71 | 1,032 | 416,731 | 6.75 |
| Com Ed | 116 | 51,047 | 0.74 | 121 | 51,530 | 0.77 | 131 | 33,518 | 0.85 |
| South MAIN | 425 | 100,553 | 2.16 | 285 | 81,040 | 1.67 | 176 | 70,521 | 1.31 |
| WIUM | 173 | 77,683 | 1.07 | 167 | 75,169 | 1.03 | 107 | 48,153 | 0.91 |
| MAPP | 462 | 250,808 | 3.99 | 439 | 254,002 | 3.87 | 277 | 224,224 | 3.60 |
| SPP North | 194 | 109,777 | 1.39 | 153 | 109,127 | 1.39 | 131 | 115,687 | 1.38 |
| SPP South | 251 | 89,773 | 2.01 | 251 | 89,773 | 1.79 | 237 | 89,793 | 1.76 |
| ERCOT | 374 | 61,069 | 3.39 | 257 | 64,714 | 3.03 | 265 | 88,257 | 3.20 |
| WA, OR | 23 | 25,367 | 0.33 | 23 | 25,367 | 0.33 | 6 | 27,331 | 0.28 |
| ID,UT,MT, parts of NV,WY | 82 | 91,779 | 0.87 | 69 | 93,242 | 0.85 | 69 | 104,850 | 0.92 |
| Northern California | - | - | - | - | - | - | - | - | - |
| Southern California and Nevada | - | - | - | - | - | - | - | - | - |
| Arizona and New Mexico | 198 | 133,000 | 1.63 | 177 | 132,823 | 1.54 | 112 | 137,866 | 1.42 |
| RMPP | 161 | 116,351 | 1.23 | 160 | 116,277 | 1.22 | 113 | 115,937 | 1.18 |
| Total | 8,900 | 2,451,209 | 44.59 | 5,215 | 2,233,393 | 32.55 | 4,310 | 2,100,750 | 30.51 |

# VII. DIFFERENCES FROM EPA IN MERCURY BANKING

Although EPA has not formally released its own modeling results for the two Hg proposals, it is widely reported that EPA's projected national Hg emissions are not reduced to the level of the 15 ton Phase II cap even by 2026 (which is the last modeled year in the simulation). The reason is that the EPA model projects that a large bank would be built up during Phase I and it would still be being drawn down at the time of the last modeled period in the EPA model.

As was described in Section VI of this paper, EPMM simulations of the Hg Cap & Trade policy proposal have a different outcome: Hg emissions reach 15 tons by 2020. There is some banking in EPMM simulations, but not to the same degree as in IPM simulations. For example, EPMM estimates that emissions at the start of Phase II (in 2018) would be 23.9 tons, but they fall to 15 tons within two years because the bank is only projected to contain 17.7 tons by the end of Phase I.

There appear to be several reasons for the substantial differences in banking behavior between EPMM simulations and EPA's purported results. These causes fall into three categories, each of which will be substantiated in this section:

1. EPA's assumes larger co-benefits than the industry believes to be correct.

    a. *Directly*, via the model inputs on the Hg removal for each existing technology and coal configuration (known as the "co-benefits" assumptions, and which were presented in Table IV-10.)

    b. *Indirectly*, because a variety of EPA's modeling assumptions lead to a relatively greater reliance on FGD over coal switching for projected $SO_2$ compliance.

2. EPA's cost and effectiveness assumptions for removal of Hg using activated carbon injection are more pessimistic than those that industry has assembled.

The net effect of these three differences motivates substantially greater banking during Phase I in EPA's model than in EPMM. In brief, EPA's model would generate lower marginal costs ($/lb Hg removed) to exactly meet a Phase I cap of 34 tons, yet it would generate higher marginal costs to exactly meet a Phase II cap of 15 tons. This means that, in the absence of banking, allowance prices simulated by EPA's model would increase at a more rapid rate than they would increase in EPMM simulations. Both models are designed to seek the same concept of a least-cost solution, however, and if banking is allowed, the least-cost response would be to decrease emissions below the cap in the early phase(s) in such a way that the marginal cost is higher at the start, and lower at the end, up to the point where marginal costs would rise at the real market interest rate over the entire time horizon of the optimization.[23] If the EPA model faces a higher rate of increase in marginal costs prior to banking, then it would tend to generate a larger amount of banking in the early years, and a later date when the last cap is physically achieved.

***EPA's DIRECT CO-BENEFITS ARE LARGER THAN INDUSTRY CO-BENEFITS***

Table IV-10 presented EPMM and EPA co-benefits side-by-side. Those are the actual model inputs. However, to understand how they affect projected Hg emissions when FGDs or SCRs are added requires further computation.[24] For example, the effect of adding a wet FGD to a cold-side ESP unit burning subbituminous coal would be a 47 percent incremental Hg reduction in EPA's simulations, while it would be a 38 percent incremental reduction in EPMM. These may seem like similar numbers, but they imply that each such FGD retrofit would reduce current unit Hg emissions 24 percent more under the EPA assumptions than under the EPMM assumptions. This particular configuration of unit also accounts for about 44 percent of existing coal units, so it is likely to have a major effect on aggregate Hg reductions due to co-benefits. Other examples of the differences in incremental Hg removal created by adding an FGD, SCR, or both are provided below for types of units that represent 78 percent of the coal fleet:

- Incremental Hg removal by adding FGD+SCR to a CESP unit (~59 percent of coal capacity in 1999)
  - EPA: 84% (bituminous) 65% (subbituminous) 44% (lignite)
  - EPMM: 77% (bituminous) 19% (subbituminous) 28% (lignite)

- Incremental Hg removal by adding an FGD to a CESP unit (~59 percent of coal capacity in 1999)
  - EPA: 47% (bituminous) 13% (subbituminous) 44% (lignite)
  - EPMM: 38% (bituminous) 19% (subbituminous) 28% (lignite)

- Incremental Hg removal by adding an SCR to a CESP+wFGD unit (~18 percent of coal capacity in 1999)
  - EPA: 71% (bituminous) 61% (subbituminous) 0% (lignite)
  - EPMM: 63% (bituminous) 0% (subbituminous) 0% (lignite)

[23] This is known as the "Hotelling price path." In a multi-pollutant setting, where there are interactions among pollutant emission rates such as co-benefits, least-cost price paths will not always follow the precise Hotelling path. However, the general principle does still underlie determination of optimal amounts of banking.
[24] The formula is ((1-CESP%)-(1-FGD+CESP%))/(1-CESP%), where CESP% is the percent removal of Hg for a unit with only a cold-side ESP, and FGD+CESP% is the percent removal of Hg for a unit with a wet FGD as well as a CESP. The respective values can be obtained from Table IV-10.

## *EPA'S ASSUMPTIONS APPEAR TO RESULT IN A GREATER RELIANCE ON FGD RETROFITS OVER COAL SWITCHING*

There are more FGD retrofits in EPA's IAQR scenario than in the EPMM IAQR scenario. For example, in 2010, EPA's IAQR scenario entails 164 GW of scrubbed units,[25] whereas there are only 122 GW of scrubbed units in the EPMM projection for the same policy.[26] (The heightened importance of FGD over coal-switching is apparent in the Base Case as well. EPA projects 115 GW of FGDs by 2010 to meet the existing Title IV cap, while EPMM projects only 88 GW of FGDs by the same time.) These extra FGDs are not a result of EPA's higher Hg co-benefits assumptions because the IAQR has no Hg constraint, and thus will not motivate any incremental retrofits due to their ability to reduce Hg. However, they do increase the quantity of co-benefits projected under the IAQR Only scenario.

EPMM sensitivity cases on the IAQR Only scenario have indicated that the propensity to use FGD over coal-switching adds substantially to the projected co-benefits. In a sensitivity case for the IAQR Only scenario that led to 64 GW of FGD retrofits by 2010 (compared to 39 GW under our base assumptions), 2010 Hg emissions dropped from 39.9 tons under the base assumptions to 36.3 tons.[27]

It is not clear why the EPA model finds FGDs more cost-effective than coal-switching compared to EPMM, but it is clear that such a difference exists. Some reasons might be differences in delivered coal prices, in the costs and other barriers to use of lower sulfur coals (either bituminous or subbituminous), differences in capitalization factors applied to capital investments, etc. A more in-depth data comparison is needed to understand which, if any, of these may be the cause. Nevertheless, the higher direct co-benefits that EPA associates with FGD installations (described in the previous section) will reinforce this greater propensity to rely on FGDs when a mercury constraint is added to the scenario.

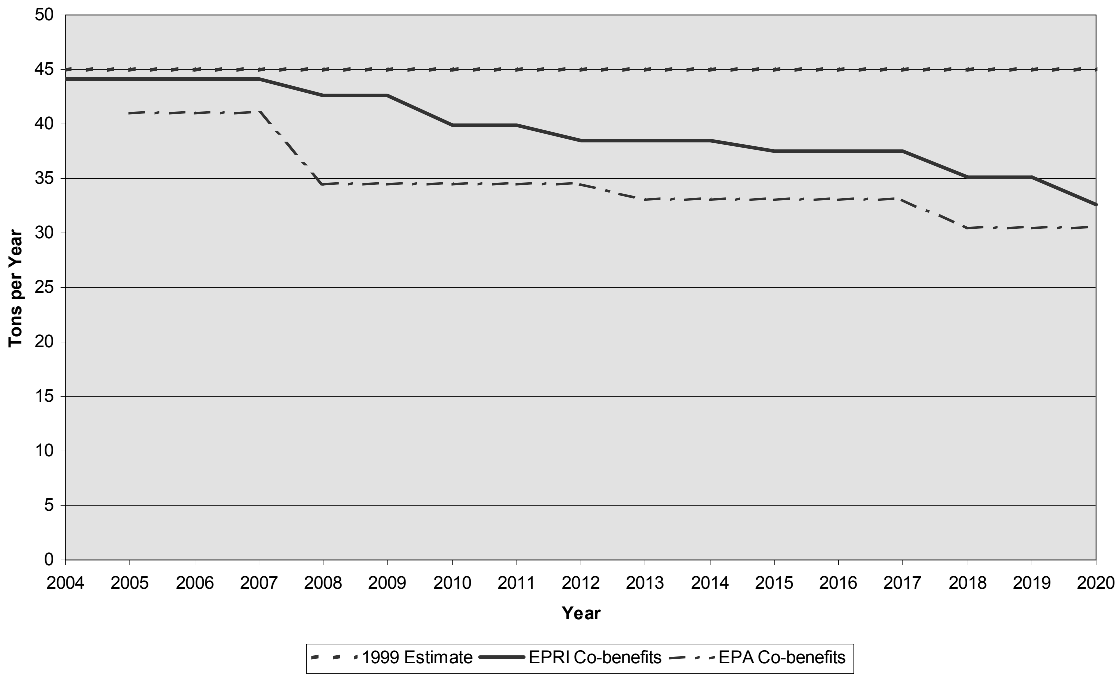
## *EVIDENCE OF HIGHER CO-BENEFITS IN SIMULATION RESULTS*

The combined effect of the direct and indirect causes of larger co-benefits in EPA's model can be observed in Figure VII-1, which contrasts EPMM's estimate of the co-benefits from just the IAQR to those estimated by EPA. One can see that EPA's co-benefits assumptions imply that Hg emissions would drop to about 34 tons by 2010, and

[25] EPA, Clean Air Markets Division "Economic & Energy Analysis for the Proposed Interstate Air Quality Rulemaking" memorandum to Docket, January 28, 2004, Table 2.
[26] The 122 GW is comprised of 83 GW already in place when the model starts running, plus 39 GW of retrofits between 2004 and 2020 (see Table VI-4).
[27] This sensitivity case eliminated any additional switching from bituminous to subbituminous coal, and no new FGD retrofits were allowed until after 2008.

EPMM's assumptions imply that Hg emissions would drop to only about 40 tons by 2010 if only the IAQR provisions (which cap only $SO_2$ and $NO_x$) were to be implemented.

**Figure VII-1. Comparison of Overall Hg Co-Benefits Estimated in EPMM and IPM (Hg Trends in IAQR-Only Scenario)**




An important implication of these results is that the marginal cost of achieving a 34-ton cap is effectively $0/ton in the EPA scenarios. In contrast, the EPMM simulations imply that the extra reduction from 40 tons down to the 34-ton cap would cost over $20,000/lb (1999$) at the margin.

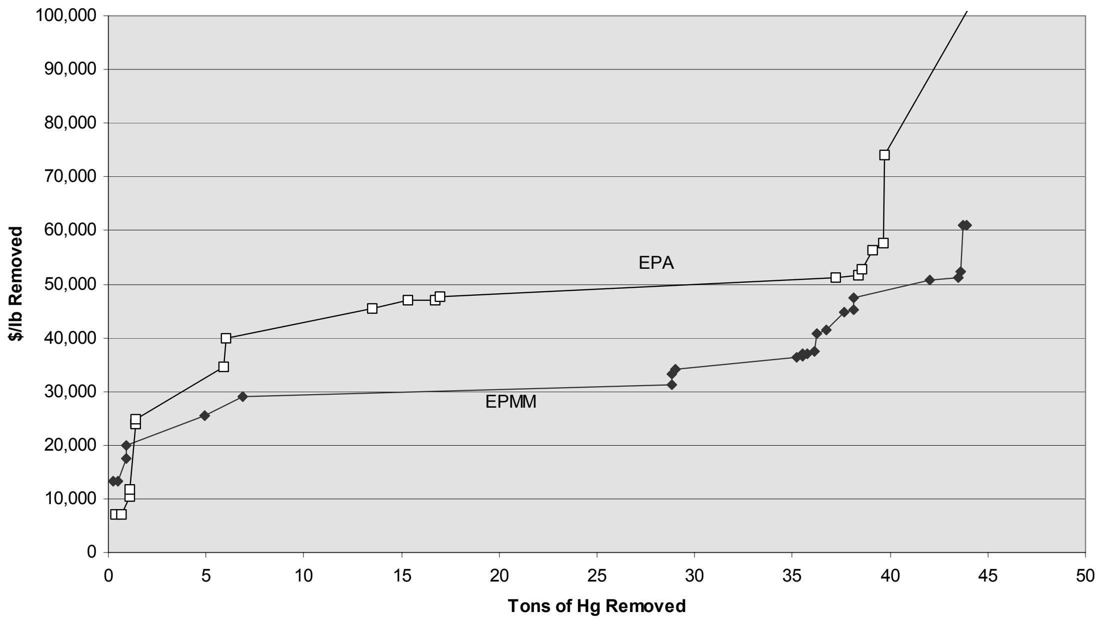
### *EPA'S COST AND EFFECTIVENESS ASSUMPTIONS FOR REMOVAL OF HG WITH ACI ARE MORE PESSIMISTIC THAN EPMM'S*

Table IV-8 presented the EPMM assumptions on the cost and removal efficiencies for activated carbon injection (ACI) technology. The comparable assumptions made by EPA are available in Attachment L1 of the IPM documentation report posted on EPA's website.[28] When either set of assumptions is combined with the respective co-benefits, one can estimate the $/lb removed implied by these inputs for each type of unit. CRA has done this for the mix technology configurations and coal types being burned in coal units in 1999, using average estimates of the coal Hg contents, heat rates, and capacity factors of all these units. Figure VII-2 plots the resulting approximate $/lb removed against the

[28] http://www.epa.gov/airmarkets/epa-ipm/attachment-l1.pdf

total potential tons that could be removed at each cost level. These approximations of the marginal cost curves in the respective models indicate that the EPA marginal cost curve for ACI is higher and steeper for all but the first few of the lowest-cost ACI retrofit options (i.e., those in the far left of the graphs).

**Figure VII-2. Comparison of $/lb Hg Removal Costs in EPA and EPMM Data**




The curves in Figure VII-2 were estimated using the mix of technologies that were in place as of 1999's ICR data collection. This included about 80 GW of scrubbed units, and none with SCRs. Both curves will rotate upwards (becoming higher and steeper) as more capacity is retrofit with FGD or SCR+FGD, as is projected under both the EPMM and EPA IAQR scenarios. Thus, the actual marginal costs associated with ACI-based controls will be higher than these curves indicate once one has layered on the co-benefits from IAQR-motivated retrofits. Given that the incremental Hg removal from most FGD and FGD+SCR installations is higher in EPA's assumptions than in the EPMM assumptions, the EPA curve would rise more than the EPMM curve if it were to be recalculated taking into account the effect of controls projected under the proposed IAQR scenario.

The EPA curve of Figure VII-2 will rise even more than the EPMM for a second reason, which is the relatively greater reliance on FGDs for $SO_2$ compliance. To the extent that more FGDs are installed in an EPA scenario, this will drive a yet wider wedge between the EPA and EPMM ACI-related marginal cost curves.

This comparison of the implications of the ACI technology assumptions further illuminates the reason the EPA model banks more Hg than EPMM during Phase I. It indicates that once co-benefits have been exhausted, and the electricity generating system must turn to ACI for further Hg reductions, the costs of those remaining reductions will be higher in the EPA model than in EPMM. It also indicates that EPA's model will see a much higher marginal cost to reduce annual Hg emissions to 15 tons than EPMM.

***SYNOPSIS ON DIFFERENCES IN MODELS' MERCURY BANKING RESULTS***

Thus, for any Phase II Hg cap that eventually exceeds the level of co-benefits, the EPA model will have a greater propensity to bank in a Phase I set at 34 tons than will be found in the EPMM model using its current assumptions. When the initial cap is set literally at co-benefits, one has created a very substantial ability to bank large amounts, because controls that generate bankable allowances are at the lowest part of the marginal cost curve. A much smaller incentive to bank is created under EPMM model assumptions because even achieving the 34-ton cap of 2010 is projected to cost $20,000 to $22,000/lb (1999$), while achieving 15 tons would only cost about $24,000 to $37,000/lb (see Table VI-7).